2.0 ALTERNATIVES INCLUDING THE PROPOSED ACTION

To determine how best to procure needed power and meet obligations to its member utilities in the face of a looming phase-out of its main existing source – and following the guidance set forth by RD to prospective loan recipients – SME conducted an alternatives analysis and an electric load analysis. Based on these analyses, SME concluded that owning its own source of electric generation is in the best interests of its members. SME then conducted a site selection analysis for a proposed facility. As a result of these analyses, SME proposes to construct a 250 MW coal-fired power plant at a site near Great Falls, Montana. This proposed action would also include construction of approximately 14 miles (23 km) of 230-kV transmission lines and about six miles (10 km) of railroad tracks for delivery of coal and limestone to the plant, in addition to several other connected actions.

SME evaluated alternatives to the proposed power plant in terms of cost-effectiveness, technical feasibility, and environmental soundness. The alternatives considered were:

1. Power Purchase Agreements – Power purchases from existing regional suppliers of wholesale electric energy and related services.

2. Energy conservation and efficiency – Demand side management and the ability of increased energy efficiency to offset the projected increases in energy demand.

3. Noncombustible renewable energy resources – Renewable energy technologies considered included wind, photo voltaic (solar), hydroelectric and geothermal.

4. Combustible renewable energy sources – Renewable combustible technologies considered included biomass, biogas, landfill gas, and municipal solid waste.

5. Nonrenewable combustible energy resources – Traditional combustible technologies considered included:
   - oil
   - natural gas-fired boilers and combustion turbines - both simple and combined cycle configurations
   - other carbon-based fuel burning technologies including fluid-bed combustion and integrated gasification combined cycle (IGCC) technology.

RD and DEQ considered these and other alternatives in this EIS and evaluated according to the purpose and need and issues identified in Chapter 1. Reasonable alternatives are fully evaluated and presented in comparative form along with the proposed action. Other alternatives were identified during scoping but were eliminated from detailed study in the EIS. The reasons for not fully evaluating these alternatives are explained in Chapter 2.

This chapter describes alternative approaches to meeting the purpose and need and addressing the issues discussed in Chapter 1. The purpose of the proposal is to meet a forecasted deficit in SME's wholesale power supply. For the alternatives described in the following sections to be considered reasonable for further consideration, they must fully meet the projected electric power needs for the SME service area.

Alternatives were evaluated in terms of their cost-effectiveness, technical feasibility, and environmental issues (consequences and constraints). The cost-effectiveness of each alternative was addressed by evaluating the initial capital costs as well as the long-term cost of operation and maintenance, including the cost of fuel over the projected life of the project. The technical feasibility of each generation option was evaluated on the basis of the alternative's ability to provide a highly reliable source of generation compatible with the energy needs as defined above. To be reasonable, an alternative must also be commercially available and capable of providing 250 MW of base load capacity by 2009 for the SME service area.

Section 2.1 describes alternatives that were considered but were eliminated from detailed evaluation in the EIS because they did not satisfy the criteria of cost-effectiveness, technical feasibility, or environmentally acceptability.

Section 2.2 describes the three alternatives evaluated in detail in the EIS.

2.1 ALTERNATIVES ELIMINATED FROM DETAILED CONSIDERATION

This section includes alternatives that were investigated, but found to not fully meet the stated requirements for detailed analysis. The rationale for their elimination is also provided.

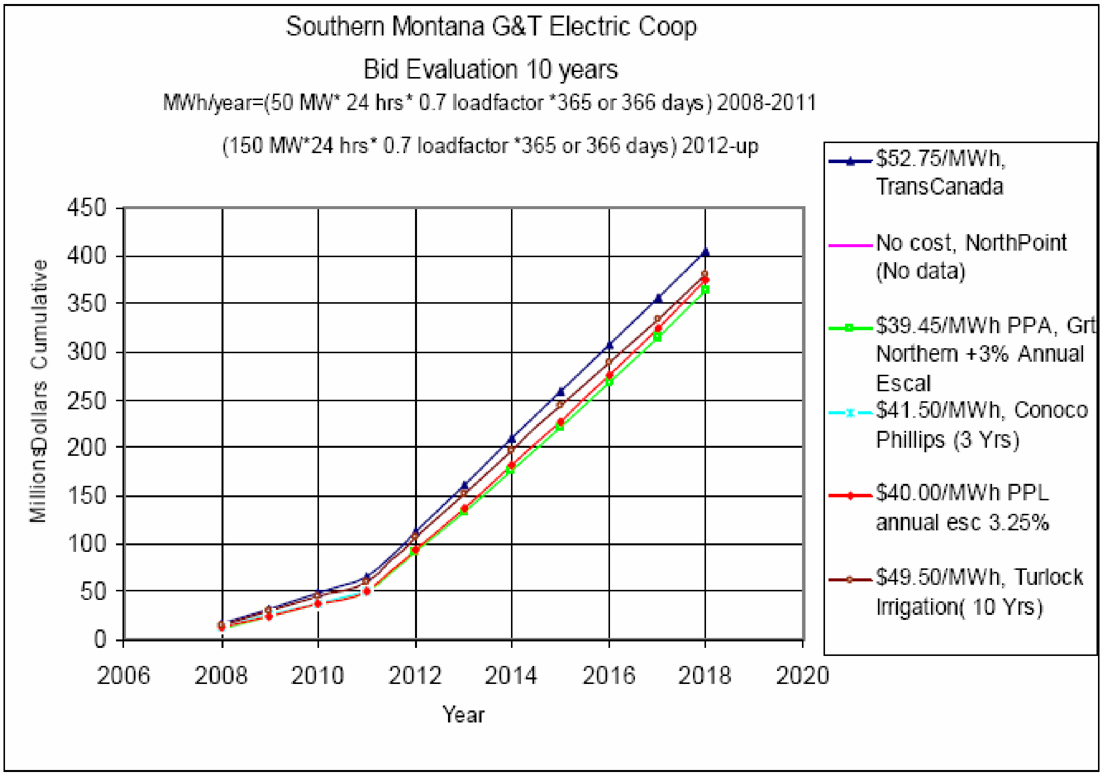
2.1.1 POWER PURCHASE AGREEMENTS

In order for a power purchase proposal to receive serious consideration, a suitable transmission path must be available from the generation source to the load control area in which SME's member systems are located. There are a number of transmission constraint points in Montana through which additional firm deliveries are not possible without considerable investments in transmission infrastructure. Non-firm transmission paths were not considered a viable option (SME, 2004a).

As explained in Chapter 1, the member cooperatives of SME currently meet their wholesale electric energy and related services obligations through the use of power purchase agreements with BPA and WAPA. In 2011, when the inherent power purchase rights in the BPA contract fully expire, the member cooperatives of SME will have a projected load of approximately 180 MW. At that time the member cooperatives of SME will have residual power purchase rights with WAPA of approximately 20 MW. If the WAPA power purchase agreement were to be completely withdrawn, the member cooperatives of SME would have a projected requirement of approximately 160 MW in 2008, escalating to approximately 180 MW by 2012 (SME, 2004a). (As noted in Chapter 1, Electric City Power of Great Falls, MT will have a load requirement of approximately 65 MW when its purchase contract with PPL expires in 2011.)

With RD's oversight and guidance, SME conducted an extensive search in the regional wholesale power supply marketplace for a suitable source of energy to meet its member system requirements with a power purchase agreement secured from an existing source of generation within the Western System Coordination Council (WSCC), of which SME is a member. Figure 2-1 shows the results of SME's November 2003 Request for Proposal (RFP) on the basis of the cumulative cost of the proposal for a 10-year period from 2009-2018.

Figure 2-1. Summary of the Results of SME's November 2003 RFP 10-year Evaluation



In January 2006, the weighted price of wholesale electricity through the Western Electricity Coordinating Council (WECC, successor to the WSCC) fluctuated between approximately $60 and $62 per MWh, or $20 per MWh – about 50 percent – more than the approximately $40 per MWh SME expects to pay to produce its own power (PowerLytix, 2006).

The lack of affordable generation capacity in the WECC, combined with ever-increasing transmission constraints, limits the future viability of purchasing capacity from existing sources of wholesale supply. As discussed in Chapter 1, the WECC has relied almost exclusively on natural gas fired generation to meet future regional supply requirements. With the cost of natural gas fired generation constituting the future marginal cost for wholesale electric energy and related supply services, the price SME would pay for power supply could be nearly double its current costs for this service commodity because of the price volatility of natural gas. Based on a search in the power supply marketplace for a suitable supply of energy, and analysis of related transmission issues, SME concluded that negotiating an acceptable power purchase agreement to meet future energy needs does not appear to be a viable option (SME, 2004a). RD concurs with this assessment.

2.1.2 ENERGY CONSERVATION AND EFFICIENCY

Energy efficiency means doing the same work with less energy. Energy efficiency improvements can free up existing energy supply. Energy efficiency incentive programs have been found to be cost-effective in terms of reducing load growth. Energy efficiency in buildings means using less energy for heating, cooling, and lighting. It also means buying energy-saving appliances and equipment for use in a building. Promotion and use of energy efficiency programs generally have neutral or beneficial effects on the environment by slowing down or eliminating the need for additional power sources.

Around the country, a number of electrical utilities sponsor programs that encourage customers to invest in energy efficiency products and energy-efficient appliances that lower consumer energy bills, delay the need for new electrical generation capacity, and reduce the emission of greenhouse gases and other pollutants. Technologies that maximize the efficient generation, transmission, and storage of energy are central to such programs (DOE, 2005a). Demand Side Management (DSM) is one example of a promising form of energy efficiency promotion; it refers to utility-facilitated actions undertaken by customers to reduce the amount or alter the timing of energy consumption (DOE, 2005b). Utility DSM programs furnish an array of measures that can lower both energy consumption and consumer energy expenses. Electricity DSM strategies aim to maximize end-use efficiency to avoid or postpone the construction of new generating plants. Means of accomplishing this include load reduction, load leveling, energy storage devices, and rate schedule/structuring such as time-of-use rates that charge consumers higher prices for peak electricity and lower prices for off-peak electricity (DOE, 2005b).

In 1997, the Montana Legislature passed Senate Bill 390, which required electric utilities and cooperatives in the state to invest a minimum of 2.4 percent of their annual retail sales in a universal systems benefits program focused on the acquisition and support of renewable energy and conservation related activities (69-8-402, *et seq.*, MCA; Gregori, 2005). Since 1997, SME's member cooperatives have complied with this state mandate to invest a portion of their total revenues in a conservation program. Conservation measures include rebates on ground source heat pumps and the installation of energy efficient appliances and retrofit lighting. The installation of equipment is almost universally replacement in kind or is located on the end user's property, thus resulting in little to no additional land use (footprint) issues. Permits that may be required are typically obtained at the local agency level through the residential or commercial / industrial building permit process. Table 2-1 documents SME expenditures in 2004 on conservation.

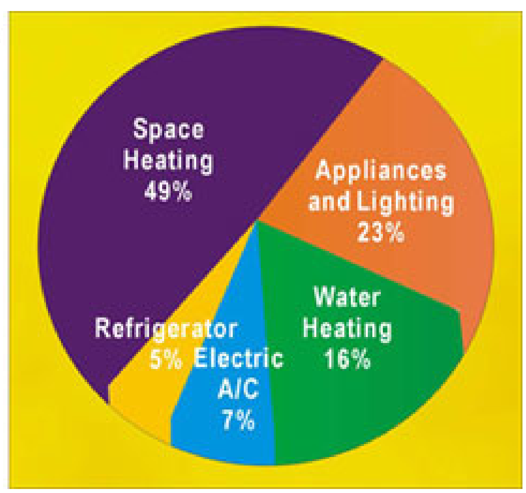


Figure 2-2. "How We Use Energy in Our Homes" – Educational Pie Chart on the *Energize Montana* Website

Table 2-1. SME System Investments in Energy Conservation in 2004

Investment Type	Beartooth	Fergus	Mid-Yellowstone	Tongue River	Yellowstone Valley	SME Total
Energy audits					$4,595	$4,595
Water heater program					$34,715	$34,715
Conservation education			$1,561		$6,393	$7,954
Demand Side Management			$9,719		$26,991	$36,710
Ground source heating					$11,737	$11,737
Energy-efficient street lighting			$449	$26	$10,263	$10,739
Distribution sys. design > min.[1]		$66,222			$63,441	$129,663
Conservation invest. in power purch.[1]	$100,897	$108,168	$46,020	$147,663	$276,530	$679,278
Totals	$100,897	$174,390	$57,750	$147,689	$434,665	$915,391

Source: SME, 2005b

[1] The last two items in Table 2-1 represent the investments SME's member systems have made on the conservation front through wholesale power purchases. For a number of years (1980's and early 1990's) electric consumers were able to apply for low and no interest loans for the purpose of investing in conservation measures such as home weatherization, installation of energy-efficient heating and cooling systems, efficient motors, etc. These loans were provided by entities such as the BPA, Montana Power Company and others with the cost being passed on to the distribution systems through the wholesale supplier. The members of SME are now repaying costs associated with this regional program. The total investment of $915,391 in 2004 amounts to approximately 4.5 percent of the SME's annual wholesale power expense.

Energy conservation is a key component of a program managed by DEQ called Energize Montana (DEQ, 2005b). Figure 2-2 is a graphic from the Energize Montana website. The website provides information for citizens, schools, businesses and government on a variety of energy-related topics, including energy conservation and efficiency. DEQ publishes the *Montana Energy Savers Guidebook* and has staffed programs in the areas of Energy Planning & Technical Assistance, Public Buildings & Renewable Energy, and Business & Community Assistance.

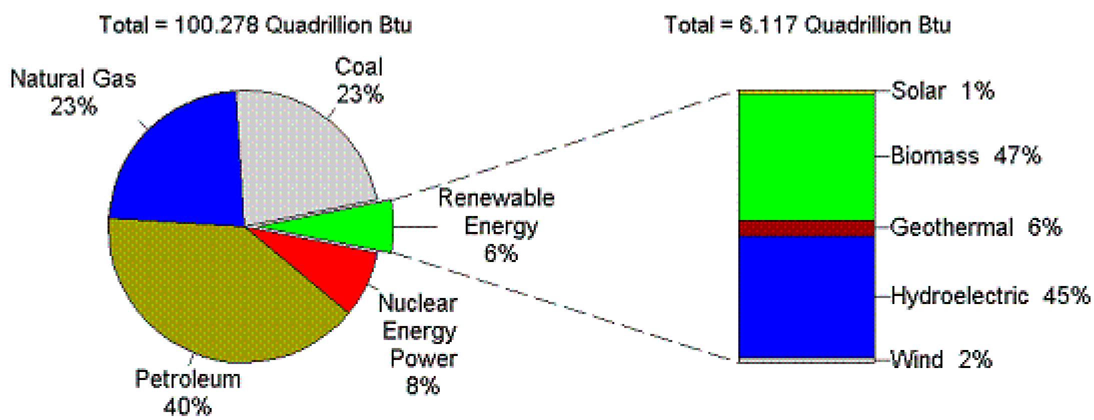
Energy efficiency programs will aid in reducing the needed capacity of future additional generation facilities. However, conservation and increased efficiency alone will not eliminate the need for additional generation capacity within the SME service area by 2009. Based on studies conducted around the country, as well as some estimates in Montana, it is reasonable to assume potential reductions in electricity use from conservation and efficiency improvements are in the 10 percent range without causing economic privation (DEQ, 2004a). This may represent the low end of the potential for conservation/efficiency. However, SME needs to replace approximately 80 percent of its existing supply by 2012; it is not technically feasible that the remaining 20 percent of its supply from WAPA could be stretched widely enough to fully supply all members and customers at a reasonable cost.

Energy conservation and efficiency programs should be pursued by SME as parallel activities alongside securing additional generation to meet projected demand.

2.1.3 RENEWABLE NON-COMBUSTIBLE ENERGY RESOURCES

The renewable, non-combustible energy resources evaluated in this section are wind, hydroelectric, solar (photovoltaic [PV] and thermal), and geothermal energy. The role of renewable energy sources in the USA's total primary energy supply in 2004 is quantified in Figure 2-3. In total, renewable energy sources supplied 6.1 quadrillion Btu's (quads), or about six percent, of the nation's total energy consumption of 100.3 quads in 2004 (EIA, 2005d). The electric power cost projections for these energy technologies are shown in Table 2-2.

Figure 2-3. The Role of Renewable Energy Consumption in the Nation's Energy Supply, 2004



Source: EIA, 2005d

Table 2-2: Electric Power Cost ($/MWh) Projections for Renewable, Non-Combustible Energy Resources*

Cost component	Wind	Solar		Hydroelectric	Geothermal[1]
		Photovoltaic	Thermal		
Capital	35.9	N/A	N/A	17.0	N/A
Fixed O & M	7.7	N/A	N/A	2.6	N/A
Variable/Fuel	7.0	N/A	N/A	4.0	N/A
Total Busbar Cost[2]	50.6	350	105	23.6	65

Source: SME, 2004a
**Levelized Costs ($/MWh) for New Utility Generating Plants in Northwest Power Pool (NWPP) Region)*

Levelized cost is the present value of the total cost of building and operating a generating plant over its economic life, converted to equal annual payments; costs are levelized in real dollars, i.e., adjusted to remove the impact of inflation.

Source for Wind Costs: U.S. Department of Energy (DOE) Energy Information Administration (EIA) *Annual Energy Outlook 2004 with Projections to 2025*. Based on the National Energy Modeling System (NEMS).

Source for Photovoltaic Costs: U.S. DOE Energy Efficiency and Renewable Energy (EERE) State Energy Information – Photovoltaic Technology website: (http:/lwww.eere.energy.gov/state_energy/technology_overview.cfm?techid=1).

Source for Thermal Solar Costs: U.S. DOE Energy Efficiency and Renewable Energy (EERE) State Energy Information – Concentrating Solar Power Technology website: (http:/lwww.eere.energy.gov/state_energy/technology_overview.cfm?techid=4).

Source for Hydroelectric Costs: U.S. DOE Idaho National Engineering and Environmental Laboratory (INEEL) Hydropower Program website: (http:/hydropower.inel.aov/facts/costs-graphs.htm).

Source for Geothermal Costs: U.S. DOE Energy Efficiency and Renewable Energy (EERE) State Energy Information - Geothermal Technology website: (http:/lwww.eere.energy.gov/state_energy/technology_overview.cfm?techid=5).

Notes:

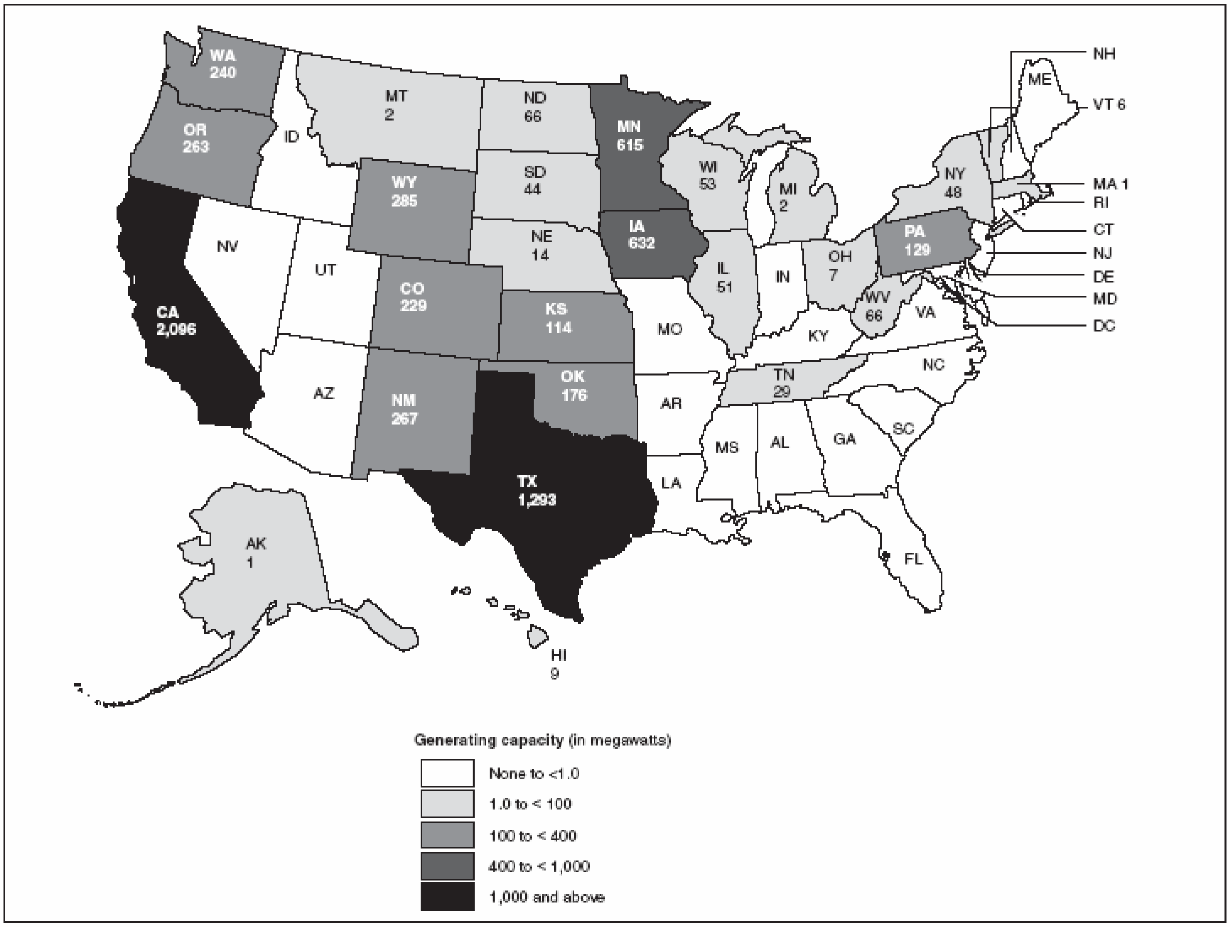
[1] Commercial geothermal resources are not available in the SME service area.
[2] Busbar Cost - wholesale cost to generate power at the plant.
$/MWh - dollars per megawatt hour
O&M - operations and maintenance

2.1.3.1 Wind Energy

Wind energy offers many advantages and is the fastest-growing renewable energy source in the world, although it still accounts for just 0.25 percent of U.S. power output. Spurred by declining costs and a growing body of local, state, and national “buy-green laws,” global wind capacity quadrupled between 1998 and 2003 (Anon., 2003). The development of wind power is increasing in many regions of the United States, including Montana (Figure 2-4). Total installed wind electric generating capacity nationwide now stands at 6,374 MW and is expected to generate approximately 16.7 billion kWh (SME, 2004a). Refer to Figure 2-5. Stimulated by the federal Production Tax Credit, which provides wind farm owners with a 1.9-cent credit per kilowatt-hour generated for the first 10 years of operation, installed wind energy capacity in the United States jumped by approximately 2,500 MW in 2005 alone, including two projects in Montana (AWEA, 2005). The industry’s trade group – the American Wind Energy Association (AWEA) – has estimated that by the end of 2005 the USA’s wind power capacity will be about 9,200 MW, enough to power roughly 2.5 million homes (Halperin, 2005). Figure 2-5 shows installed capacity as of January 2005.

Figure 2-4. Modern Wind Turbine at Judith Gap, Montana, Installed in 2005

Figure 2-5. Installed Wind Power-Generating Capacity by State, in MW, as of Jan. 2005*



Source: American Wind Energy Association.

***does not include Judith Gap wind power project in Montana, with 150 MW installed later in 2005**

Wind is a clean energy source that does not pollute the air or produce greenhouse gases like carbon dioxide or atmospheric emissions that can cause acid rain or visibility reduction. Although wind power plants have relatively little impact on the environment compared to conventional power plants, there is some concern over the noise produced by the rotor blades and aesthetic (visual) impacts; furthermore, birds have been killed by flying into the rotors (DOE, 2005c). Avian deaths have become a concern at Altamont Pass in California, which is an area of extensive wind development and also high year-round raptor use. Detailed studies and monitoring following construction at other wind development areas indicate that this may be a site-specific issue. Areas that are commonly used by threatened or endangered bird species may be unsuitable for wind development. Wind energy can also negatively impact birds and other wildlife by fragmenting habitat, both through installation and operation of wind turbines themselves and through the roads and power lines that may be needed (AWEA, 2004).

A 2001 review for the National Wind Coordinating Committee (a collaborative effort of the wind industry, environmental groups, and other stakeholders) of existing studies of avian collisions with wind turbines concluded that avian collision mortality was much lower than other sources of avian collision mortality in the United States (WEST, 2001). This study predicted that even if wind plants became much more numerous and widespread, they would still likely cause no more than a few percent of all bird deaths from collision with manmade structures. However, there is not yet a consensus among wildlife biologists more generally as to wind energy's long-term impacts.

A 2005 review of available research by the U.S. Government Accountability Office (GAO, formerly called the General Accounting Office) found that the impact of wind power installations on wildlife generally varies by region and by species. Specifically, studies have shown that wind power facilities in northern California and in Pennsylvania and West Virginia have killed large numbers of raptors and bats, respectively. Studies in other parts of the country have shown comparatively lower levels of mortality, although most facilities have killed at least some birds. However, numerous wind power facilities in the U.S. have not been studied to date, and therefore scientists are unable to reach definitive conclusions about the risk that wind power poses to wildlife in general. Uncertainties remain. Moreover, much is still unknown about migratory bird flyways and overall species population levels, impeding the analysis of the cumulative impact that wind power may have on wildlife species. This field of research is still in its infancy, as is large-scale wind power itself. To date, few studies exist on how to reduce wildlife fatalities at wind power facilities. Overall, based on what is known so far, it does not appear that existing wind power development accounts for a significant amount of bird mortality. Nevertheless, it is premature to conclude that the potential cumulative impact on birds and bats of any widespread expansion of wind power in the country would be insignificant (GAO, 2005).

For its part, the U.S. Fish and Wildlife Service, in its interim guidance on avoiding and minimizing wildlife impacts from wind turbines, states: "…wind energy facilities can adversely impact wildlife, especially birds and bats, and their habitats. As more facilities with larger turbines are built, the cumulative effects of this rapidly growing industry may initiate or contribute to the decline of some wildlife populations" (USFWS, 2003).

Another issue with some early wind turbine designs was noise, but it has been largely eliminated as a problem through improved engineering and through appropriate use of setbacks from nearby residences. Aerodynamic noise has been reduced by changing the thickness of the blades' trailing edges and by positioning machines "upwind" rather than "downwind" so that the wind hits the rotor blades first, then the tower. (On downwind designs, where the wind hits the tower first, its "shadow" can cause a thumping noise each time a blade passes behind the tower.) A small amount of noise is generated by the mechanical components of the turbine. To put this into perspective, a wind turbine 300 meters away is no noisier than the reading room of a library (AWEA, 2004).

Scenic coastal areas and mountain ridges (Figure 2-6) are often characterized by high wind intensity and good to excellent wind energy potential (DOE, 2005g; Anon., 2001). Thus, certain proposed wind developments have been opposed on the basis of aesthetic or visual resource concerns, most notably in recent years the Cape Wind Project in Nantucket Sound, Massachusetts, which would be the USA's first offshore wind farm (Cape Wind, no date; ACE, 2004). This proposed 130-turbine project would generate approximately 450 MW of clean, renewable energy, yet has split public opinion and environmentalists, drawn bipartisan opposition and support, and even become an issue in Massachusetts' 2006 gubernatorial race (Dennehy, 2005).

Figure 2-6. Wind Farm on West Virginia's Backbone Mountain, Visible from Blackwater Falls State Park

Wind power must compete with conventional generation sources on a cost basis. Wind energy is one of the lowest-priced renewable energy technologies available today. State-of-the-art wind power plants can generate electricity for less than 5 cents/kWh with the Production Tax Credit in many parts of the U.S. (AWEA, 2004). Technological advances have improved the performance of wind turbines and driven down their cost. In locations where the wind blows steadily, the cost of wind power has been shown to compete favorably with coal and natural gas fired power plants (if the full cost including "firming" (see Section 2.2.2.3) is not considered). Even though the cost of wind power has decreased dramatically in the past 10 years, the technology requires a higher initial investment than fossil-fueled generators. Fixed, investment-related costs are the largest component of wind-based electricity costs. Improved designs with greater capacity per turbine have reduced investment costs to approximately $750-to-$1,000/kW. Wind power plants incur no fuel costs, however, and their maintenance costs have also declined with improved designs. Not including the cost of firming, the Energy Information Administration (EIA) projects the levelized cost of wind power to be approximately $50.6/mWh (refer to Table 2-2).

The big challenge to using wind for electrical power is that it is intermittent and the electricity generated cannot be stored effectively. Thus it is not considered a "firm" resource. Not all winds can be harnessed to meet the timing of electricity demands. Due to the intermittent nature of wind, a wind power plant's economic feasibility strongly depends on the amount of energy it produces. Capacity factor serves as the most common measure of a wind turbine's productivity. Capacity factor is the ratio of the net electricity generated, for the time considered, to the energy that could have been generated at continuous full-power operation during the same period. The capacity factor for wind plants is normally in the 25 to 40 percent range (AWEA, 2004).

Another major issue regarding wind intermittence is that wind power can provide energy, but not on-demand capacity. Even at the best sites, there are times when the wind does not blow sufficiently and no electricity is generated. Related to intermittence is wind's unpredictable nature. Weather forecasting has improved over the past several decades, so wind power plant operators can predict, to some extent, what their output will be by the hour. However, that ability is imperfect at best. Therefore, wind power cannot always be reliably dispatched at the time it is needed. If wind is generating more than about 20 percent of the electricity that a system is delivering in a given hour, the system operator begins to incur significant additional expense because of the need to procure additional equipment that is solely related to the system's increased variability (AWEA, 2004).

Good wind resource areas with accessibility to nearby existing transmission lines do exist; however, it is more common that wind resources are located some distance from adequate transmission lines. Larger wind developments (several hundred megawatts) are more likely to invest in new transmission infrastructure.

Wind turbines can be used in off-grid applications, or they can be connected to a utility power grid. For utility-scale sources of wind energy, a large number of turbines are usually built close together to form a wind farm. In open, flat terrain, a utility-scale wind plant will require about 60 acres (24 hectares) per MW of installed capacity. However, only five percent or less of this area is actually occupied by turbines, access roads, and other equipment, while 95 percent remains free for other compatible uses such as farming or ranching (AWEA, 2004).

As a renewable resource, wind is classified according to wind power classes, which are based on typical wind speeds. These classes range from class 1 (lowest) to class 7 (highest). In general, a wind power class 4 or higher can be useful for generating power with large (utility-scale) turbines, and small turbines can be used at any wind speed. Class 4 and above are considered good resources. Montana has wind resources consistent with utility-scale production (DOE, 2005g). Good-to-excellent wind resource areas are distributed throughout the eastern two-thirds of Montana (Figure 2-7). The region east of the Rockies in northern Montana has excellent-to-superb wind resource, with other outstanding resource areas being located on the hills and ridges between Great Falls and Havre. The region between Billings and Bozeman also has excellent wind resource areas. Ridge crest locations have the highest resource in the western third of the state (DOE, 2005g).

Although most of SME’s service area is rated at class 3 (fair wind resources), areas with a wind power class of 4 or higher are present within the SME service territory. This portion of the SME service area has the potential to support large-scale wind farm facilities with an estimated annual capacity factor of approximately 30 percent. Therefore, it is technically feasible to develop wind farms within the general SME service area (DOE, 2005g).

A 250-MW wind farm would require approximately 72 square miles (46,000 acres or 186 sq. km) of area based on an average power output of 3.47 MW/square mile for wind power class 4 resources. Because of the intermittent nature of wind power and the large land requirements, wind power alone cannot realistically fulfill the need for 250 MW of highly reliable base load capacity. SME currently receives a portion of its energy output from a large wind farm through its contract with BPA. This 5-MW source is currently available to the customers of the member cooperatives through SME (SME, 2004a).

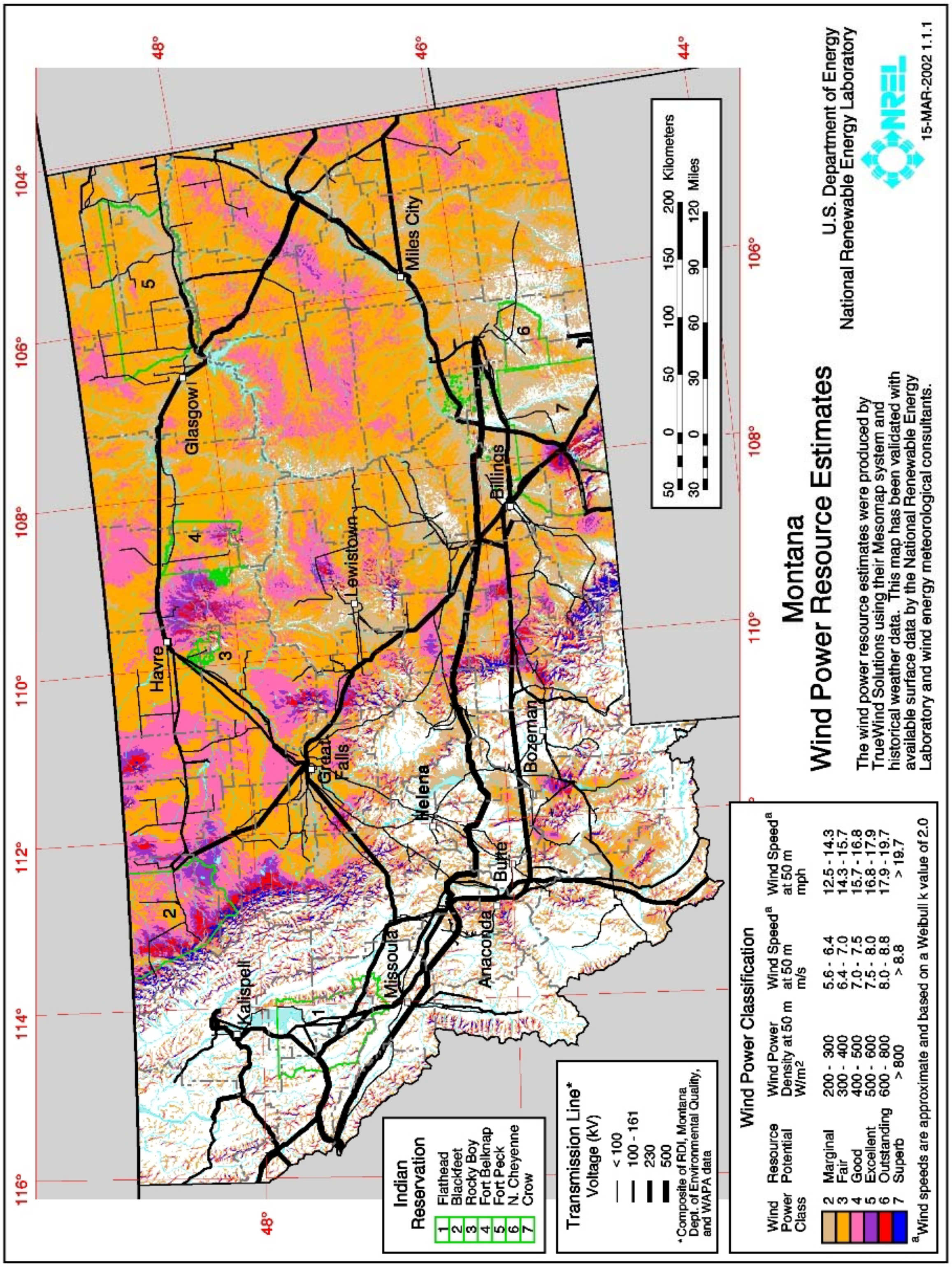


Figure 2-7. Montana Wind Resources (*Source: DOE, 2005i*)

2.1.3.2 Solar Energy

Figure 2-8. Solar Photovoltaic System

Renewable energy technologies can convert solar energy into electricity (Figure 2-8). Solar resources are expressed in watt-hours per square meter per day. This is roughly a measure of how much solar radiation strikes a square meter over the course of an average day.

Flat-plate solar systems are flat panels that collect sunlight and convert it to either electricity or heat. These technologies include photovoltaic (PV) systems, which include a flat-plate collector installed in a tilted position. A flat-plate collector generally obtains the most available solar energy if it is tilted toward the south at an angle equal to the latitude of the location. Because of their simplicity, flat-plate collectors are often used for residential and commercial building applications. They can also be used in large arrays for utility applications.

Concentrating solar power technologies use reflective materials such as mirrors to concentrate the sun's energy (Figure 2-9). This concentrated heat energy is then converted into electricity. Concentrating solar power is the least expensive solar electricity for large-scale power generation (DOE, 2005d). Solar concentrators usually are mounted on tracking systems in order to face the sun continuously. This allows the collectors to capture the maximum amount of direct solar rays. Because these systems usually require tracking mechanisms, solar concentrators are generally used for large-scale applications such as utility or industrial use.

The Western Governors Association (WGA) estimates that, with a longer-term federal investment tax credit and state-based incentives, the western United States could install as much as eight gigawatts (8,000 MW) of solar electric generating capacity by 2015, enough to power four million homes (REA, 2005). According to the WGA, deployment on this scale could also reduce solar costs to a point where they are competitive with power produced from fossil fuels. A WGA task force in 2005 envisioned half of solar deployment developed in central concentrating solar power plants and half developed in distributed PV generation. According to the U.S. DOE however, Montana's climate and northern latitude render it a marginal resource for solar concentrators (DOE, 2005b). The most promising role for solar energy in Montana may not be in centralized, utility-operated power plants, but rather in distributed applications such as hot water and space heating, as well as electricity generation in residences, commercial buildings, farms, and ranches.

Figure 2-9. Concentrating Solar Power (solar thermal trough) System in California's Mojave Desert

Utilizing solar energy generally produces environmental benefits (NCAT, no date). It is both renewable and sustainable. There are no major water discharge issues and no major direct air emissions related to the installation of a solar facility. Carbon emissions are avoided, as are SO_2 and NOx emissions. There could be minor sources of air emissions resulting from the installation of miscellaneous support equipment such as diesel/natural gas emergency generators. The fact that the structures associated with solar energy installations are generally not nearly as tall as modern wind turbines means that they have not generated the same concern and controversy over aesthetic impacts as have wind farms. Likewise, solar energy facilities have not been implicated in bird and bat kills, as have some wind facilities. However, within the confined footprint of development, centralized solar energy facilities virtually eliminate native habitat.

A 250-MW PV solar farm located in the best area of Montana for solar power would require approximately 310 acres (125 hectares), or less than 0.5 square mile (1.3 sq. km) (SME, 2004a). The aesthetic effects of a facility of this relatively small size would be unlikely to generate public concern and controversy.

Fixed, investment-related charges are the largest component of solar-based electricity costs. The DOE Energy Information Administration projects the capital cost component of the levelized cost of solar power to be approximately $350/mWh for PV and $105/mWh for thermal solar (SME, 2004a). Solar power units incur no fuel costs. Maintenance costs are low for PV systems but are high for thermal solar applications.

Due to the intermittent nature of solar power, economic feasibility strongly depends on the amount of energy it produces. Capacity factor serves as the most common measure of solar power productivity. Estimates of capacity factors range from 20 to 35 percent. Because solar power is dependent on the weather, it is unpredictable and cannot offer on-demand capacity.

Solar power alone could not reasonably fulfill the need for 250 MW of a reliable base load capacity within the SME service area for the reasons discussed above. In particular, Montana has a marginal solar resource, and solar power production in the SME service area would be intermittent.

2.1.3.3 Hydroelectricity

The most common type of hydroelectric power plant uses either a dam on a river to store water in a reservoir or a run of the river approach, which does not result in the construction of a large reservoir (Figure 2-10) (DOE, 2001). Water released from the reservoir flows through a turbine, which in turn activates a generator to produce electricity. Another type of hydroelectric power plant is referred to as a pumped storage plant. The plant turbines turn

Figure 2-10. Bureau of Reclamation's Hungry Horse Dam & Reservoir on the South Fork of the Flathead River near Kalispell, Montana

backward to pump water from a river or lower reservoir to an upper reservoir, where the potential energy is stored. To use the energy, the water is released from the upper reservoir back down into the river or lower reservoir. This turns the turbines forward, activating the generators to produce electricity (DOE, 2005e).

To have a usable hydropower resource, there must be both a large volume of flowing water and a change in elevation. Due to the seasonal nature of hydropower, the average annual capacity factor for most facilities is approximately 40 to 50 percent. Another major issue regarding hydropower is its year-to-year unpredictable output due to annual rainfall variability.

There are no major direct air emissions related to the utilization of hydroelectric resources. There could be minor sources of air emissions resulting from the installation of miscellaneous support equipment such as diesel/ natural gas emergency generators. The major impacts would likely be to the aquatic environment, alteration of river flows, and land use alterations. The construction of an impoundment or reservoir could have various adverse impacts on water quality, wetlands, flooding of bottomland and upland habitats or agricultural areas, and aquatic biota (EPA, 2005a). Fish populations can be impacted if adults cannot migrate upstream past impoundment dams to spawning grounds or if juveniles cannot migrate downstream. (This is much more of an issue west of the continental divide, where Pacific salmon stocks occur.) Fish injury and mortality can also result from passage through turbines. Advanced turbine technology reduces fish mortality resulting from turbine passage to less than 2 percent, in comparison with turbine-passage mortalities of 5 to 10 percent for the best existing turbines and 30 percent or greater from other turbines (INL, 2005a). Advanced turbine technology also can maintain downstream dissolved oxygen levels to help ensure compliance with water quality standards.

Fixed, investment-related charges are the largest component of hydroelectric power plant costs. The DOE's Idaho National Engineering and Environmental Laboratory (INEEL) reports hydropower capital costs to be $1,700 to $2,300/kW. Operating and maintenance costs are low for hydropower. The total levelized cost of hydropower is projected to be approximately $24/MWh (refer to Table 2-2).

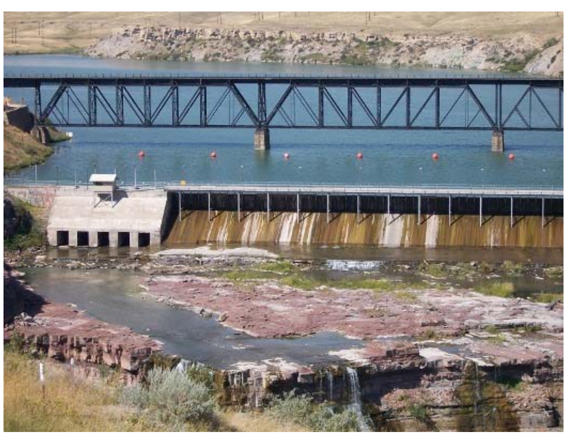


Figure 2-11. One of PPL Montana's Great Falls Dams that Generate Hydroelectricity along the Missouri River (Rainbow Dam at Rainbow Falls)

One of the principal issues facing hydropower is the extent to which additional expansion of capacity is even possible or realistic, due to opposition by environmental groups to further development of U.S. rivers. A 1998 study by the INEEL for the U.S. DOE modeled undeveloped hydropower capacity on a national basis, for the first time taking into account environmental, legal, and institutional constraints (Connor et al., 1998). Whereas past efforts to quantify undeveloped U.S. hydropower capacity ranged across an order of magnitude, from approximately 50,000 MW to almost 600,000 MW, the more realistic 1998 assessment identified 5,677 sites with a total undeveloped capacity of approximately 30,000 MW. According to this study, 158 hydroelectric projects with an adjusted, undeveloped capacity of 1,014 MW could be developed in Montana (Table 2-3). The projects include:

- expansions of existing power projects;
- developing hydropower projects at existing dams; and
- projects at undeveloped sites.

Because of the lack of significant precipitation, runoff, and topographic relief in south-central and southwestern Montana, the region lacks the available hydroelectric resources capable of providing 250 MW of generation from a single power plant. Attempting to provide 250 MW in a timely fashion by constructing multiple facilities would likely be rendered infeasible by the lengthy Federal Energy Regulatory Commission (FERC) licensing process and possible delays resulting from opposition by environmental groups (FERC, 2005).

Table 2-3. Unadjusted and Adjusted Undeveloped Hydropower Capacity in Montana

Category	Number of Projects	Unadjusted, undeveloped capacity (MW)	Adjusted, undeveloped capacity (MW)
Developed sites with existing power	7	470	235
Developed (dammed) sites without existing power	72	1,129	502
Undeveloped sites	79	2,073	277
State total	158	3,672	1,014

Source: Connor et al., 1998
"Unadjusted, undeveloped capacity" refers to downward adjustments to hypothetical capacity unadjusted for environmental, legal, and institutional constraints

2.1.3.4 Geothermal Energy

Around the world, geothermal energy – "heat from the earth" – is a proven resource both for direct heat and power generation (World Bank, no date). This energy source is contained in underground reservoirs of steam, hot water, and hot dry rocks. Two types of geothermal resources are being tapped commercially: hydrothermal fluid resources and earth energy. Hydrothermal fluid resources, which are reservoirs of steam or very hot water, are well suited for electricity generation. Due to the remote locations of many geothermal resources, the cost of transmission may make development of these energy sources more expensive than a facility that is closer to an identified interconnection point. Earth energy, the heat contained in soil and rocks at shallow depths, is excellent for direct use and geothermal heat pumps but not as a source of electric power generation.

Producing electricity from geothermal resources involves a mature technology. Approximately 8,000 MW of geothermal electric capacity are currently in service around the world, including approximately 2,200 MW of capacity in the United States. All of the geothermal power in the

Figure 2-12. CalEnergy Navy I Flash Power Plant at the Coso Geothermal Field in California (85 MW net capacity)

U.S. is generated in California, Nevada, Utah, and Hawaii, with California accounting for over 90 percent of installed capacity. A considerable amount of this – 1,137 MW – is generated at one northern California facility, the Geysers. This site is an ideal and fairly unusual resource because its wells produce virtually all steam with little water carry over.

In general, geothermal reservoirs are classified as either low temperature (<150° C) or high temperature (>150° C). The high temperature reservoirs are most suited for commercial production of electricity. Three types of geothermal plants have been developed: dry steam, flash steam, and binary. Dry steam power plants, the first kind to be developed, use the steam from the geothermal reservoir as it comes from wells, routing it directly through turbine/generator units to produce electricity. In flash steam plants, the most prevalent type of geothermal electric plant in operation today, water at temperatures greater than 360° F (182° C) is pumped under high pressure to the generation equipment at the ground surface. Upon reaching this equipment the pressure is suddenly reduced, allowing some of the hot water to convert or "flash" into steam. This steam is then used to power the turbine/generator units and produce electricity. The remaining hot water not flashed into steam, and the water condensed from the steam, are generally pumped back into the reservoir (INL, 2005b).

Binary cycle power plants differ from dry steam and flash steam systems in that the water or steam from the geothermal reservoir never comes into contact with the turbine/generator units. Rather, the water from the geothermal reservoir is used to heat another "working fluid," which is vaporized and used to turn the turbine/generator units. The geothermal water and the "working fluid" are each confined in separate circulating systems or "closed loops." The advantage of the binary cycle system is that it can operate with lower temperature waters (225° F - 360° F), by using working fluids that have an even lower boiling point than water. Binary cycle power plants also produce no air emissions (INL, 2005b).

Geothermal energy is generally one of the cleaner forms of energy available for commercial applications. Small direct heat resources have minimal air and water emissions. Large geothermal resources utilized for electrical generation have air emissions consisting primarily of hydrogen sulfide (H_2S), ammonia (NH_3), and methane (CH_4). These developed projects also have water discharges, and would need additional controls to minimize emissions. New designs are able to minimize emissions within the process and with the use of add-on emissions control equipment. The high flow rates of steam and water from geothermal wells can result in the precipitation of various compounds on the steam generating and turbine equipment. These precipitates are primarily silica. Frequent cleaning of the equipment would result in land disposal of the precipitates. Land use for geothermal resources is normally small compared to fossil energy resources. A 20- MW geothermal power plant would require approximately three acres (1.2 hectares). Therefore, 13 of these plants having a total output of 250 MW would require a total area of approximately 39 acres (16 hectares).

Montana has low to moderate temperature resources that could be tapped for direct heat or for geothermal heat pumps. However, electric generation is not possible with these resources. Therefore, geothermal electric power cannot fulfill the need for 250 MW of highly reliable base load capacity within the SME service area because commercial geothermal resources for the generation of electric power are not available in the state (SME, 2004a).

2.1.4 Renewable Combustible Energy Resources

The renewable combustible energy resources evaluated in this section are biomass, biogas, and municipal solid waste (MSW). The electric power cost projections for these energy technologies are shown in Table 2-4.

Table 2-4. Electric Power Cost ($/MWh) Projections for Renewable, Combustible Energy Resources*

Cost Component	Biomass	Biogas	Municipal Solid Waste
Capital	N/A	37.0	32.8
Fixed O&M	N/A	6.6	38.9
Variable/Fuel	N/A	3.0	13.0
Total	90.0	46.5	84.8

Source: SME, 2004a
*Levelized Costs ($/MWh) for New Utility Generating Plants in NWPP Region

Source for Biomass Costs: U.S. Department of Energy (DOE) Energy Efficiency and Renewable Energy (EERE) State Energy Information - Biomass Power Technology website:(http://www.eere.energy.gov/state_energyttechnology_overview.cfm?techid=3)

Source for Biogas Costs: U.S. DOE Energy Information Administration (EIA) *Annual Energy 2003 Outlook* Reference Case. Based on the National Energy Modeling System (NEMS).
$/MWh - dollars per megawatt hour

A significant environmental issue for these renewable, combustible technologies is air emissions. Table 2-5 documents projected emissions of key air pollutants from a hypothetical 250-MW power plant using biomass and municipal solid waste as fuel.

2.1.4.1 Biomass

The term "biomass" means any plant-derived organic matter available on a renewable basis, including dedicated energy crops and trees, agricultural food and feed crops, agricultural crop wastes and residues, wood wastes and residues, aquatic plants, animal wastes, municipal wastes, and other waste materials. Biomass can be used to provide heat, make fuels, chemicals and other products, and generate electricity. Bio-energy ranks second (to hydropower) in renewable U.S. primary energy production and accounts for three percent of the primary energy production in the United States (DOE, 2005d). However, on an equivalent heat basis, biomass actually ranks first among renewable energy sources. (Refer to Figure 2-3.)

Table 2-5. Estimated Annual Air Emissions (tons/year) for a 250-MW Generating Station Using Biomass or Municipal Solid Waste[1]

Technology	Sulfur dioxide (SO_2)	Nitrogen oxides (NOx)	Carbon monoxide (CO)	Particular Matter (PM_{10})	Hazardous Air Pollutants (HAPs)	Mercury (Hg)	GHGs[2]
Biomass	274	2,409	6,570	810	427	0.038	342[3]
Municipal Solid Waste	439	4,886	1,911	132	54	0.29	2,668,000[4]

Source: SME, 2004a; EPA, 2003l; EPA, 1996

[1]For biomass, based on 250-MW wood-fired boiler with low-NO_X burners and fabric filter; average fuel heating value of 6,500 British thermal units (Btu) per pound (lb). For municipal solid waste, based on mass burn water well combustor, 4,500 Btu/lb; 2,443,000 tons refuse derived fuel per year (RDF/yr); Lime Spray Drier, Fabric Filter, and Selective Catalytic Reduction (at 80 percent control); AP-42, Section 2.1 emission factors.
[2]Greenhouse Gases
[3] CO_2 emitted from this source is generally not counted as greenhouse gas emissions because it is considered part of the short-term CO_2 cycle of the biosphere (USEPA, 2003l).
[4] CO_2 emitted from municipal solid waste combustion may increase total atmospheric CO_2 because emissions may be offset by the uptake of CO_2 from regrowing biomass (USEPA, 1996).

Heat can be used to chemically convert biomass into a fuel oil, which can be burned like petroleum to generate electricity. Biomass can also be burned directly to produce steam for electricity production or manufacturing processes. In a power plant, a turbine utilizes the steam to turn a generator that converts the energy into electricity. Some coal-fired power plants use biomass as a supplemental energy source in high-efficiency boilers to significantly reduce emissions (DOE, 2005d).

Biomass can also produce gas for generating electricity. Gasification systems use high temperatures to convert biomass into a gaseous mixture of hydrogen, carbon monoxide, and methane. The gas then fuels a combustion turbine, which is very much like a jet engine, except that it turns an electric generator instead of propelling a jet. The decay of biomass in landfills also produces a gas – methane (CH_4) – that can be burned in a boiler to produce steam for electricity generation or for industrial processes (DOE, 2005d).

Wood is the most commonly used biomass fuel for heat and power and is an available biomass resource in Montana. The most economic sources of wood fuels are usually urban residues and mill residues. Urban residues used for power generation consist mainly of chips and grindings of clean, non-hazardous wood from construction activities, woody yard and right-of-way trimmings, and discarded wood products such as waste pallets and crates. Mill residues, such as sawdust, bark, wood scraps, and sludge from paper, lumber, and furniture manufacturing operations are typically very clean and can be used as fuel by a wide range of biomass energy systems. These forest industries exist in Montana, and offer potential fuel sources for power generation. However, these waste materials are often burned in boilers at the plants themselves to produce thermal and/or electric power used to run the mills (SME, 2004a).

Biopower technologies are proven electricity generation options in the United States, with 10 gigawatts (10,000 MW) of installed capacity. All of today's capacity is based on mature, direct-combustion technology. Direct combustion involves the burning of biomass with excess air, producing hot flue gases that are used to produce steam in the heat exchange sections of boilers. The steam is used to produce electricity in steam turbine generators (DOE, 2005f).

The primary pollution issue in utilizing biomass to generate electricity is the control of air emissions. Co-firing of biomass fuels in a coal-fired boiler is advantageous from a renewable energy point of view as well as an alternative to land disposal of biomass as a solid waste. Biomass used as 5-15 percent of the fuel input in the co-firing of a coal-fired boiler would have similar air emissions and control requirements as those for a conventional pulverized coal or circulating fluidized bed boiler discussed later in this chapter. A 250 MW biomass-only fired boiler would have estimated air emissions shown in Table 2-5. While a biomass-fired boiler would have relatively low emissions of sulfur dioxide (SO_2), emissions of nitrogen oxides (NOx), carbon monoxide (CO), particulate matter (PM), and hazardous air pollutants (HAPs) would typically be higher than conventional coal-fired boilers or natural gas-fired combustion turbines.

The cost to generate electricity from biomass varies depending on the type of technology used, the size of the power plant, and the cost of the biomass fuel supply. In today's direct-fired biomass power plants, generation costs are approximately $90/MWh (SME, 2004a). Co-firing is an emerging technology that has been evaluated for a variety of boiler technologies, including pulverized coal, cyclone, fluidized bed and spreader stokers. Co-firing refers to the practice of introducing biomass in high-efficiency, coal-fired boilers as a supplemental energy source. For utilities and power generating companies with coal-fired capacity, co-firing with biomass may represent one of the least-cost renewable energy options (DOE, 2005g). For biomass to be economical as a fuel for electricity, the source of biomass must be located near the power generation facility to reduce transportation costs.

SME examined the possibility of a 20-MW biomass facility utilizing wood waste from pulp mills in Montana and concluded it was not feasible due to the location and uncertainties associated with the wood waste supply. For biomass to be economical as a fuel to generate electricity, the source of biomass must be located close to the power plant. This reduces transportation costs; the preferred system has transportation distances below 100 miles (approx. 260 sq. km). The most economical conditions exist when the energy use is located at the site where biomass residues are generated (i.e., at a paper mill or sawmill). These conditions do not exist for SME. Thus, a 250-MW biomass facility would not be cost-effective compared to a conventional, pulverized coal-fired or circulating fluidized bed power plant (SME 2004a).

2.1.4.2 Biogas

Biomass gasification for power production involves heating biomass in an oxygen-starved environment to produce a medium or low calorific gas. This biogas is then used as fuel in a combined cycle power generation plant that includes a gas turbine topping cycle and a steam turbine bottoming cycle (DOE, 2005g).

Anaerobic digestion by anaerobic bacteria (whose survival requires an environment devoid of oxygen) is a naturally-occurring process (CanREN, 2003). "Swamp gas," which contains methane, is produced by the anaerobic decomposition of wetland vegetation that has settled to the bottom of a marsh, swamp or other wetland. Environmental concerns and rising energy costs for energy and for wastewater treatment have led to a resurgence of interest in anaerobic treatment and new interest in using biogas produced during this treatment of organic wastes.

The same types of anaerobic bacteria that produce natural gas also produce methane-rich biogas today. Anaerobic bacteria break down or "digest" organic material in a two-step process. The first step is to break down the volatile solids in a waste stream to fatty acids. The second stage of the process is environmentally sensitive to changes in temperature and pH and must be free of oxygen to produce biogas as a waste product. The anaerobic processes can be managed in a "digester" (an airtight tank) or a covered lagoon (a pond used to store manure) for waste treatment. The primary benefits of anaerobic digestion are nutrient recycling, waste treatment, and odor control. Except in very large systems, biogas production is considered a secondary benefit (SME, 2004a).

In most cases, the methane produced by the digester is well-concentrated. Because methane is the principal component of natural gas, it is an excellent source of energy for use either in cogeneration on the electrical grid or simply for fueling boilers at the wastewater treatment plant. The methane captured from an anaerobic digester will naturally contain some impurities, chiefly sulfur, which should be scrubbed prior to pressurization and combustion. Anaerobic digesters are used in municipal wastewater treatment plants and on large farm, dairy, and ranch operations for disposal of animal waste.

Landfill biogas (LFG) is created when organic waste in a landfill naturally decomposes. This gas consists of about 50 percent methane, about 50 percent carbon dioxide, and a small amount of non-methane organic compounds. Instead of allowing LFG to escape into the air, it can be captured, converted, and used as an energy source. Using LFG helps to reduce odors and other hazards associated with LFG emissions, and it helps prevent methane from migrating into the atmosphere and contributing to local smog and global climate change.

The various types of biogas can be collected and used as a fuel source to generate electricity using conventional generating technology. Production of electric power from both digester gas and landfill gas has been demonstrated commercially for many years (SME, 2004a). The DOE Energy Information Administration projects the capital cost component of the levelized cost of biogas power to be approximately $37/MWh in 2009. The total levelized cost of biogas power is projected to be approximately $46/MWh (refer to Table 2-4).

Using digester or landfill gas as a fuel in a turbine is environmentally beneficial because biogas is a renewable resource. Pretreatment of the digester or landfill gas is very important to the long-term viability of the engines or turbines. The gas is typically treated to remove hydrogen sulfide, siloxanes, moisture, and particulates prior to combustion. The primary environmental compatibility issue is the air emissions produced by combustion. Air emissions for a turbine firing digester or landfill gas are similar to those of a natural gas-fired combustion turbine. The use of Selective Catalytic Reduction (SCR) for nitrogen oxide (NOx) control and catalytic oxidation for carbon monoxide (CO) control may be required. There are no major issues with biogas concerning water discharge or solid waste/hazardous waste generation. A 20-MW biogas facility would require approximately three acres (1.2 ha). Therefore, 13 of these plants having a total output of 250 MW would require a total area of approximately 39 acres (16 ha).

The current U.S. Environmental Protection Agency (EPA) Landfill Methane Outreach Program landfill and project database lists four landfill sites in Montana that have the potential for a landfill gas to electric power project. Two of the landfills are located within or near the SME service territory. One is located in Bozeman (owned and operated by the City of Bozeman), which is near the service territory and the other is located in Great Falls (owned and operated by Montana Waste Systems) which is within the service territory. The other two landfill locations are located at Missoula and Kalispell which are considerable distances to the SME service area. There are no landfills in Montana currently using landfill gas for energy production. The ability of a landfill to use the LFG for power generation is based on the rate of gas production. Gas production is dependent on the volume of waste in place, the age of the waste, and the moisture content of the waste. Landfills in Montana are dry and produce less gas than landfills in other parts of the country. Because of its low population, the total volume of waste produced in Montana is less than about 43 other states.

For SME or other Montana electric generation utilities, the key issues for biogas facilities are the dispersed locations and insufficient quantities of the fuel source. The City of Great Falls is currently developing a small-scale biogas generating facility in conjunction with its wastewater treatment plant. The amounts of digester gas and landfill gas resources are limited within the SME service area. Therefore, biogas power cannot fulfill the need for 250 MW of highly reliable base load capacity.

Figure 2-13. MSW: Pile of Used Newspapers

2.1.4.3 Municipal Solid Waste

The municipal solid waste industry includes four components: recycling, composting, landfilling, and waste-to-energy via incineration. Municipal Solid Waste (MSW) is total waste excluding industrial waste, agricultural waste, and sewage sludge. Medical wastes from hospitals and items that can be recycled are also generally excluded from MSW used to generate electricity. As defined by the U.S. EPA, MSW includes durable goods, non-durable goods, containers and packaging, food wastes, yard wastes, and miscellaneous inorganic wastes from residential, commercial, institutional, and industrial sources. Examples from these categories include: appliances, newspapers, clothing, food scraps, boxes, disposable tableware, office and classroom paper, wood pallets, rubber tires, and cafeteria wastes. Waste-to-energy combustion and landfill gas are byproducts of municipal solid waste (EIA, 2005e).

MSW can be directly combusted in waste-to-energy facilities to generate electricity. Because no new fuel sources are used other than the waste that would otherwise be sent to landfills, MSW is often considered a renewable power source. Although MSW consists mainly of renewable resources such as food, paper, and wood products, it also includes nonrenewable materials derived from fossil fuels, such as tires and plastics (EPA, 2005b).

At the power plant, MSW would be unloaded from collection trucks and shredded or processed to ease handling. Recyclable materials would be set aside, and the remaining waste would be fed into a combustion chamber to be burned. The heat released from burning the MSW would be utilized to produce steam, which turns a steam turbine to generate electricity.

Burning MSW produces nitrogen oxides, CO_2, and SO_2 as well as trace amounts of toxic pollutants, such as mercury compounds and dioxins. Variability in the composition of MSW affects the emissions produced. For example, if MSW containing batteries and tires are burned, toxic materials can be released into the air. A variety of air pollution control technologies are used to reduce toxic air pollutants from MSW power plants (EPA, 2005b). Estimated emissions of criteria air pollutants from a 250-MW MSW electric-generation facility are comparable or lower than a coal-fired resource, however, the emissions of hazardous air pollutants including mercury, cadmium, and toxic organics are considerably higher (SME, 2004a).

Power plants that burn MSW are normally smaller than fossil fuel power plants but typically require a similar amount of water per unit of electricity generated. Similar to fossil fuel power plants, MSW power plants discharge used water. Pollutants build up in the water used in the power plant boiler and cooling system. In addition, the cooling water is considerably warmer when it is discharged than when it was taken. This discharge would require a permit and would have to be monitored (EPA, 2005b).

MSW power plants reduce the need for landfill capacity because disposal of ash created by MSW combustion requires less volume and land area as compared to unprocessed MSW. However, because ash and other residues from MSW operations may contain toxic materials, the power plant wastes must be disposed of in an environmentally safe manner to prevent toxic substances from migrating (leaching) into ground-water supplies. Current regulations require MSW ash sampling on a regular basis to determine its hazardous status. Hazardous ash must be managed and disposed of as hazardous waste. Depending on state and local restrictions, non-hazardous ash may be disposed of in a MSW landfill or recycled for use in roads, parking lots, or daily covering for sanitary landfills (EPA, 2005b).

The United States has approximately 90 operational MSW-fired power generation plants, generating approximately 2,500 megawatts, or about 0.3 percent of total national power generation. However, because construction costs of new plants have increased, economic factors have limited new construction (EPA, 2005b). The capital cost of an MSW power project is approximately $3,500 to $4,000/kW. The total levelized cost of MSW power is projected to be approximately $85/mWh (refer to Table 2-4). Typically, MSW power plants become economical only when landfills for MSW disposal are not available near the collection area and hauling costs become excessive. The MSW power plants can command a tipping fee to offset the high cost of power production, but these need to be in the $50 to $60/ton range in order for the plant to be competitive. These conditions exist in populous areas such as New York City. Except for small, localized areas, the potential for economical power to be generated in Montana from MSW does not exist. SME serves rural areas and does not have a municipal customer base large enough to support a municipal solid waste-to-energy project (SME, 2004a). There are currently no MSW incinerators operating in the State of Montana.

2.1.5 Non-Renewable Combustible Energy Resources

The non-renewable combustible energy resources evaluated in this section are Natural Gas Combined Cycle (NGCC), microturbines, Pulverized Coal (PC), and Integrated Gasification Combined Cycle (IGCC) coal. The electric power cost projections for these energy technologies are documented in Table 2-6 below.

As with the renewable, combustible technologies discussed above, a significant environmental issue for the non-renewable, combustible technologies is air emissions. Table 2-7 documents projected emissions of key air pollutants from a hypothetical 250-MW power plant from non-renewable, combustible energy sources.

Table 2-6. Electric Power Cost Projections for Non-Renewable, Combustible Energy Resources*

	Levelized Costs ($/MWh)				
Cost Component	Natural Gas Combined Cycle (NGCC)	Microtubines	Subcritical Pulverized Coal (PC) Powder River Basin (PRB) Coal	Circulating Fluidized Bed (CFB) Powder River Basin (PRB) Coal	Integrated Gasification Combined Cycle (IGCC) Bituminous Coal
Capital	19.0	49.1	33.8	25.2	42.8
Fixed O&M	2.3	8.4	4.6	4.6	3.3
Variable / Fuel	41.0	55.7	11.7	12.8	19.8
Total Bus-bar Cost[1]	62.3	113.2	50.1[2]	42.6	65.9

Source: SME 2004a
**Levelized Costs for New 250 MW Power Plant (Microturbines @ 30 kW), 90 Percent Capacity Factor*
[1] Busbar Cost-wholesale cost to generate power at the plant.
[2] EIA, 2004a: Table 21 for Advanced Coal plant.
$/mWh dollars per megawatt hour
O&M operations and maintenance

2.1.5.1 Natural Gas Combined Cycle

Natural gas combined cycle power plants generate electricity using two cycles – the steam cycle and the gas cycle (PF, 2005). In the steam cycle, fuel is burned to boil water and create steam which turns a steam turbine, driving a generator to create electricity. In the gas cycle, gas is

Table 2-7. Estimated Annual Air Emissions (tons/year) for a 250 MW Generating Station, from Non-Renewable, Combustible Energy Sources[1]

Technology	Sulfur dioxide (SO_2)	Nitrogen oxides (NOx)	Carbon monoxide (CO)	Particulate Matter (PM_{10})	Hazardous Air Pollutants (HAPs)	Mercury (Hg)	GHGs[2]
NGCC[3]	30	87	131	58	9	---	963,000
Microturbines	83	83	1,250	83	---	---	1,691,666
Pulverized coal	1,330[6]	887[6]	1,330[6]	166	33	0.05	1,941,000
CFB[4] coal	142[7]	887[7]	710[7]	89[7]	18[7]	0.05[8]	1,941,000[9]
CFB (HGS)[10]	437	805	1,150	345	20	0.02	2,300,000
IGCC[5] coal	1,242	790	364	133	NA	0.05	1,553,000

Source: SME, 2004a (updated April 2005) and Draft Air Quality Permit #3423-00

[1]For natural gas combined cycle, based on 250-MW Combined Cycle Turbine; 8,000 Btu/gross kWh heat rate; 90% NOx removal with selective catalytic reduction (SCR); AP-42 Section 3.1 emissions factors. For microturbines, based on summed emissions of 8,333 microturbines, each 30 kW in size; 0.437 MMBtu/hr heat input; 80% capacity factor; Dry Low NOx combustion; emission factors based on AP-42 Section 3.1 and EPA paper, *Technology Characterization: Microturbines,* March 2002. For pulverized coal, based on pulverized coal boiler, Powder River Basin (PRB) coal 8,000 British thermal units (Btu)/pound; 9,000 Btu/gross kilowatt hours (kWh) heat rate; 1,108,700 tons/yr coal; lime spray dryer, fabric filter and selective catalytic reduction; AP 42 emissions factors; U.S. Department of Energy (DOE) Energy Information Agency (EIA) Carbon Dioxide (CO_2) factor of 1,970 lb/megawatt hours (MWh). For circulating fluidized bed coal, based on circulating fluidized bed boiler; Powder River Basin (PRB) coal 8,000 British thermal units (Btu)/pound (lb); 9,000 Btu/gross kilowatt hours (kWh) heat rate; 1,108,700 tons/yr coal; limestone flash dryer absorber desulphurization, fabric filter and selective non-catalytic reduction. For integrated gasification combined cycle coal, emissions are based on Tampa Electric Polk Power Station IGCC Project. HAPs emissions were not reported but are expected to be lower than a conventional pulverized coal boiler but higher than a conventional natural gas combined cycle turbine. Carbon dioxide emissions are estimated to be 20% less than conventional pulverized coal boiler.
[2]Greenhouse Gases
[3]Natural Gas Combined Cycle
[4]Circulating Fluidized Bed
[5]Integrated Gasification Combined Cycle, testing eastern coals with higher sulfur content
[6]These emissions values were extracted from recent air permits issued in the state of Montana and were found to be comparable with the AP42 emissions factors.
[7] Information obtained from CFB boiler suppliers.
[8]AP42 Emissions Factors.
[9]U.S. DOE EIA carbon dioxide factor of 1970 lb/megawatt hours (MWh).
[10] Proposed permit limits from HGS Draft Air Quality Permit #3423-00.

burned in a gas turbine which directly turns a generator to create electricity (refer to Figure 2-14). Combined cycle power plants operate by combining these two cycles for higher efficiency; that is, a higher percentage of the innate chemical energy of the fuels is converted into heat and kinetic energy. The hot exhaust gases exiting the gas turbine are routed to the steam cycle and are used to heat or boil water. These exhaust gases typically carry away up to 70 percent of the energy in the fuel before it was burned, so capturing what otherwise would be wasted can double overall efficiency from 30 percent for a gas cycle only plant to 60 percent using the newest combined cycle technology (PF, 2005).

Gas turbines for electric utility services generally range from a minimum of 20 MW for peaking service up to the largest machines for use in combined cycle mode (SME, 2004a). In the early 1990’s natural gas played a major role as a heating fuel of choice for homes and commercial and business establishments, and also became the premier fuel for new electric generation. Natural gas was easy to locate, economical, and environmentally friendly. During this period, virtually

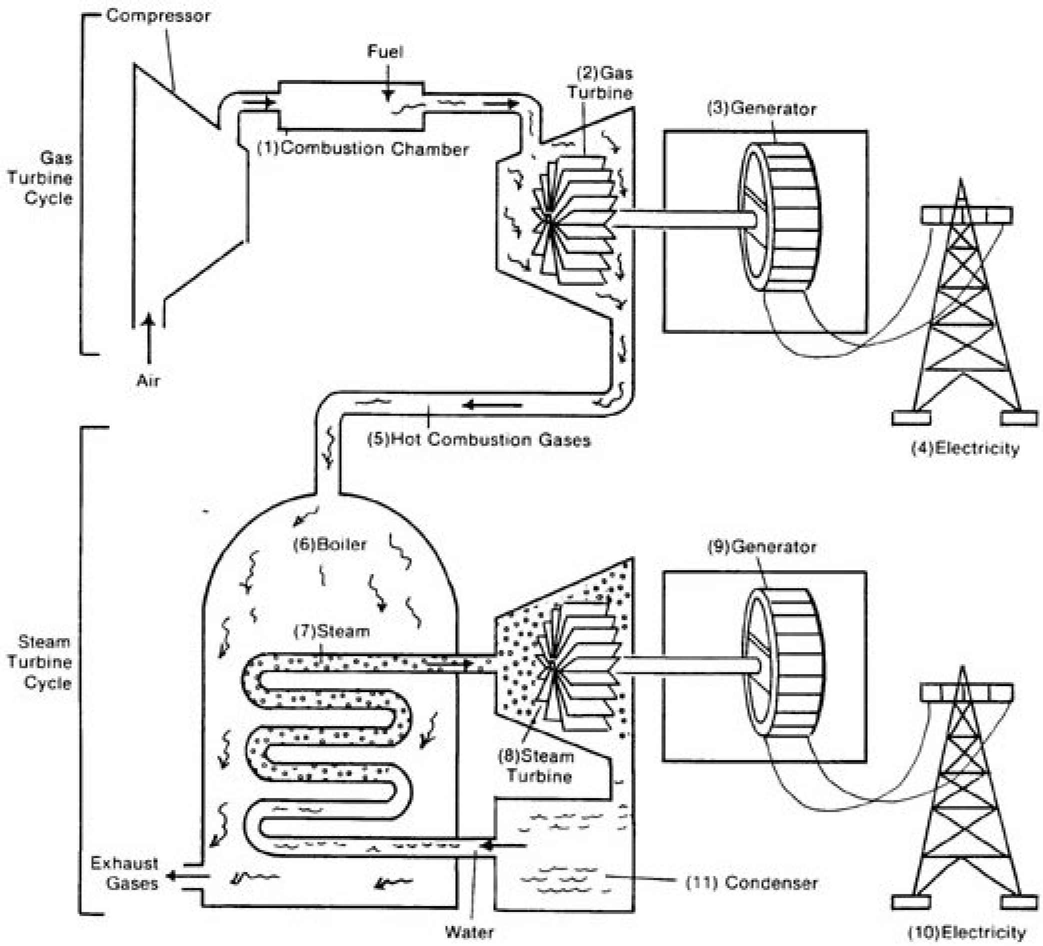


Figure 2-14. Major Elements of Natural Gas Combined Cycle System

all new generation built in the region was in the form of combined or simple cycle gas turbines. Most new base load power plant facilities built in the United States in the past 10 years have used NGCC technology. NGCC plants have demonstrated high reliability and low maintenance costs (SME, 2004a).

Environmentally, as documented in the air emissions rates in Table 2-7, NGCC is clearly superior to other non-renewable energy resources. Assessing the entire life cycle, one of NGCC's drawbacks is the loss of potent greenhouse gas methane during extraction and distribution (Spath and Mann, 2000). Even though air pollution concerns are much lower with gas-fired plants than oil or coal-fired plants, there are other environmental concerns, including water use and water pollution. Combined cycle plants use about 10 million gallons of water per day, consuming seven million and discharging three million gallons back into nearby water bodies (PF, 2005).

More recently, because of the increased supply burden placed on natural gas, its price is increasing significantly, which affects not only the price of electricity produced by gas-fired generation but also the cost to heat homes and businesses. Because of highly variable and volatile natural gas fuel costs, as well as the likelihood of significant future price rises as domestic production crests and demand continues to intensify, NGCC is not a reliable, cost-effective option to meet the energy needs of the SME service area.

2.1.5.2 Microturbines

Microturbines are small combustion turbines, approximately the size of a refrigerator, with outputs of 25-500 kW. They evolved from automotive and truck turbochargers, auxiliary power units for airplanes, and small jet engines and are composed of a compressor, a combustor, a turbine, an alternator, a recuperator, and a generator. Microturbines offer a number of potential advantages over other technologies for small-scale power generation. These include their small number of moving parts, compact size, light weight, greater efficiency, lower emissions, lower electricity costs, and ability to use waste fuels. They can be located on sites with space limitations for the production of power, and waste heat recovery can be used to achieve efficiencies of more than 80 percent (DOE, 2005h).

Because of their compact size, relatively low capital costs, low operations and maintenance costs, and automatic electronic control, microturbines are expected to capture a significant share of the distributed generation market (DOE, 2005h). Types of applications include stand-alone primary power, backup/standby power, peak shaving and primary power (grid parallel), primary power with grid as backup, resource recovery and cogeneration. Target customers include financial services, data processing, telecommunications, office buildings and other commercial sectors that may experience costly downtime when electric service is lost from the grid (SME, 2004a).

In general, microturbine power plants are not currently cost competitive with conventional power-generation technologies. The capital cost of a microturbine unit is approximately $2,500/kW. The total levelized cost of microturbine power is projected to be approximately $113/mWh. Typically, microturbine units become economical for remote locations, when grid power is not available, and when low cost waste fuel is available (SME, 2004a). The U.S. Department of Energy's Office of Power Technologies is currently leading a national effort to design, develop, test, and demonstrate a new generation of microturbine systems for distributed energy resource applications. The goal is to develop advanced microturbines that will be cleaner, more fuel efficient and fuel-flexible, more reliable and durable, and lower in cost than the first-generation products entering the market today (DOE, 2005f).

Currently, microturbine units alone cannot fulfill the need for 250 MW of long-term, cost-effective, and competitive generation of base load capacity for the SME service area.

2.1.5.3 Pulverized Coal

Modern pulverized coal plants generally vary widely in size from 80 MW to 1,300 MW and can use coal from various sources. Coal is most often delivered by unit train to the site, although barges or trucks are also used. Many plants are situated adjacent to the coal source where

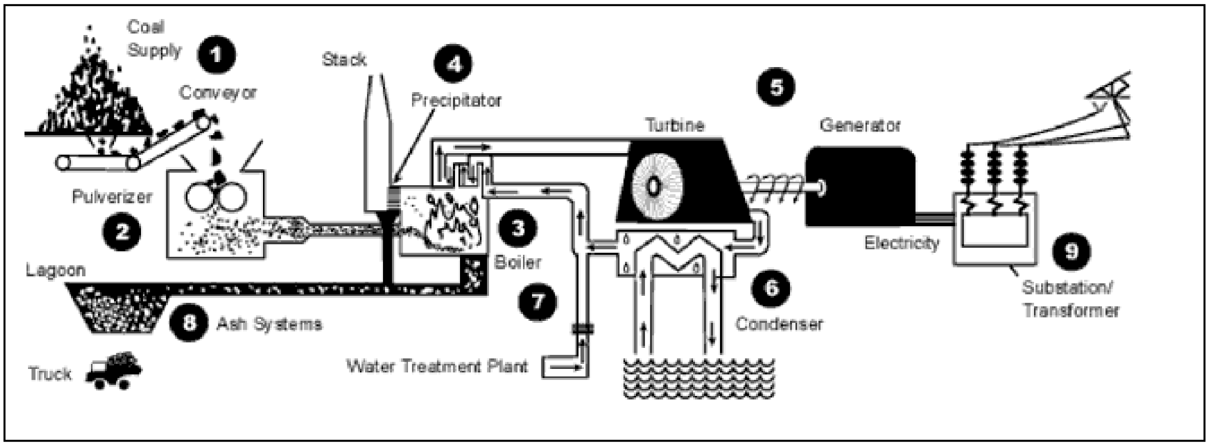


Figure 2-15. Diagram Depicting Components of a "Generic" Pulverized Coal Power Plant

delivery can be by conveyor. Coal can have various characteristics with varying Btu heating values, sulfur content, and ash constituents. The source of coal and coal characteristics can have a significant effect on the plant design in terms of coal-handling facilities and types of pollution control equipment required (SME, 2004a).

Regardless of the source, the plant coal-handling system unloads and stacks out the coal, reclaims the coal as required, and crushes the coal for storage in silos. Then the coal is fed from the silos to the pulverizers and blown into the steam generator (Figure 2-15). The steam generator mixes the pulverized coal with air, which is combusted, and in the process produces heat to generate steam. Steam is conveyed to the steam turbine generator, which converts the steam thermal energy into mechanical energy. The turbine then drives the generator to produce electricity (SME, 2004a).

Estimated air emissions for a 250 MW pulverized coal plant are documented in Table 2-7. Pollution control equipment would include either a fabric filter (bag house) or an electrostatic precipitator for particulate control (fly ash), selective catalytic reduction for removal of NOx, and a flue gas desulfurization system (FGD) for removal of SO_2. Limestone is required as the reagent for the most common wet FGD process, limestone forced oxidation desulphurization. A limestone storage and handling system is a required design consideration with this system (SME, 2004a).

Pulverized coal plants represent the majority of coal-fired electric generating stations in the country, and coal-fired thermal plants generate more electricity than any other type in the United States. Because of the widespread use of PC plants, their air emissions are major contributors to a wide array of significant and cumulative environmental problems, including acid rain, visibility reduction, mercury emission, deposition and accumulation, and global warming (Applied Geochemistry Group, 2001; Eilperin, 2004; EPRI, 1998; IPCC, 2004; Kenworthy, 2004; Malm, 1999; EPA, 2005a; EPA., 2005b; EPA, 2004a; EPA, 2004b; EPA, 2003a; EPA, 2003b; EPA, 2003c; EPA, 2003d; EPA, 2003e; EPA, 2003f; EPA, 2003g; EPA, 2003h; EPA, 2003i; EPA, 2003j; EPA, 2003k; EPA, 2002c; EPA, 2000c; EPA, 1998c; EPA, 1997; USGS, 2000a; Suplee, 2000).

Pulverized coal plants produce several forms of liquid and solid waste. Liquid wastes include cooling tower blowdown, coal pile runoff, chemicals associated with water treatment, ash-conveying water, and FGD wastewater. Solid wastes include bottom and fly ash and FGD solid wastes. Disposal of these wastes is a major factor in plant design and cost considerations (SME, 2004a).

PC plants, although having a high capital cost relative to some alternatives, have an advantage over other non-renewable combustible energy source technologies due to the relatively low and stable cost of coal. New conventional pulverized coal plants achieve above 40 percent efficiency. Advanced modern plants use specially developed high strength alloys, which enable the use of the supercritical and ultra-supercritical steam (high pressures and temperatures) necessary to achieve the higher cycle efficiencies and can achieve, depending on location, close to 45 percent efficiency (CURC, 2005).

Constructing and operating a PC plant typically requires numerous permits and approvals from federal and state regulatory agencies. A major source Prevention of Significant Deterioration (PSD) air construction permit would be required from DEQ. The permit application, agency review, and public comment process can be extensive for a new coal-fired resource.

A PC generating station would have the benefit of relatively low cost and high reliability for base load generation for SME. However, these advantages are offset by the somewhat greater emissions of PC plants (Table 2-7) and the higher probability that the environmental community might choose to actively oppose a new PC plant. Therefore, this alternative is eliminated from more detailed consideration in this EIS.

2.1.5.4 Integrated Gasification Combined Cycle Coal

IGCC is a power generation process that integrates a gasification system with a conventional combustion turbine combined cycle power block. Rather than burning coal (or other feedstock) directly, the gasification system breaks it down to its basic chemical constituents. Coal is exposed to hot steam and carefully controlled amounts of oxygen under high temperatures and pressures. Carbon molecules in the coal then rupture, initiating chemical reactions that produce a synthetic gas or syngas consisting of carbon monoxide, hydrogen and other compounds (DOE, 2006a). This combustible syngas is then used to fuel a combustion turbine to generate electricity, and the exhaust heat from the combustion turbine is used to produce steam for a second generation cycle and provide steam to the gasification process (Rosenberg et al., 2005).

IGCC is an emerging, advanced technology for generating electricity with coal that can substantially reduce some air emissions, water consumption, and solid waste production from coal power plants. IGCC offers the potential for using coal in electricity generation with improved environmental performance, particularly reduced air emissions, through gasification and removal of impurities prior to combustion. This emissions control method is very different from PC power plants, which achieve virtually all emissions control through combustion and post-combustion controls that treat exhaust gases. Because the syngas produced in the gasification process has a greater concentration of pollutants, lower mass flow rate, and higher pressure than stack exhaust gas, emissions control through syngas cleanup is generally more cost-effective than post-combustion treatment to achieve the same or greater emissions reductions (Rosenberg et al., 2005). Overall environmental impacts from emissions of an IGCC plant would be expected to range somewhere between those of a natural gas combined cycle plant and a pulverized coal plant (Table 2-7). As shown in Table 2-7, air emissions from IGCC and CFB plants are similar (taking into account higher sulfur coal used in Polk Power tests) with the exception of particulate matter and CO emissions, which are lower for an IGCC plant.

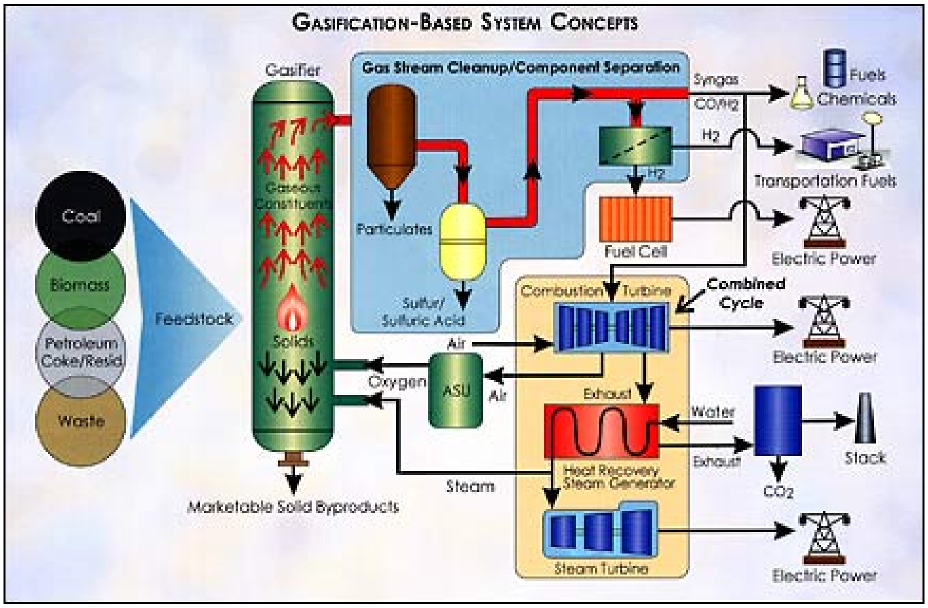


Figure 2-16. Gasification-based System Concepts (DOE, 2006b)

Minerals in the fuel such as rocks, dirt and other impurities separate and leave the bottom of the gasifier either as an inert glass-like slag or other marketable solid products. Only a small fraction of the mineral matter is blown out of the gasifier as fly ash and requires removal downstream. Sulfur impurities in the feedstock form hydrogen sulfide, from which sulfur can be easily extracted, typically as elemental sulfur or sulfuric acid, both of which are valuable byproducts. Nitrogen oxides, another potential pollutant, are not formed in the oxygen-deficient (reducing) environment of the gasifier. Instead, ammonia is created by nitrogen-hydrogen reactions; ammonia can be readily stripped out of the gas stream (DOE, 2006b).

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The use of these two types of turbines in combination – a combustion turbine and a steam turbine – known as a "combined cycle," is one reason why gasification-based power systems can achieve unprecedented power generation efficiencies (refer to Figure 2-16). Currently, gasification-based systems can operate at around 45 percent efficiencies; in the future, these systems may be able to achieve efficiencies approaching 60 percent. In contrast, a conventional coal-based boiler plant, employing only a steam turbine-generator, is typically limited to 33-40 percent efficiencies (DOE, 2006b).

DOE also believes coal gasification may be one of the best ways to produce clean-burning hydrogen for automobiles and power-generating fuel cells. It might also offer greater potential for sequestering carbon dioxide at a lower cost, thereby reducing emissions of this greenhouse gas (DOE, 2006b).

DOE is currently spearheading “FutureGen,” a $1 billion public-private partnership to build the world's first coal-fueled, "zero emissions" power production plant (FutureGen, 2006a). Partners in the “FutureGen Industrial Alliance” include seven American coal companies and utilities and one Chinese utility, coordinated by the non-profit Batelle research and industrial firm. A prototype, consisting of a 275-MW FutureGen plant, is slated to begin operations in 2012. It will produce electricity for about 150,000 homes using the IGCC process, as well as hydrogen and a concentrated stream of carbon dioxide. The hydrogen will be used as a clean fuel in applications such as electricity generation in turbines or fuel cells, or hybrid combinations of these technologies. Captured CO_2 will be separated from the hydrogen and permanently stored in deep saline formations, unmineable coal seams, depleted oil and gas formations, or other geologic formations. Ninety percent of the total carbon dioxide produced by the plant is expected to be captured initially, and with advanced technologies, this type of plant may eventually be able to capture up to 100 percent of carbon dioxide emissions (FutureGen, 2006a; DOE, 2006d).

At present however, IGCC technology still has insufficient operating experience for widespread expansion into commercial-scale, utility applications. Each major component of IGCC has been broadly utilized in industrial and power generation applications. But the integration of coal gasification with a combined cycle power block to produce commercial electricity as a primary output is relatively new and has been demonstrated at only a handful of facilities around the world, including two in the United States (DOE, 2006c).

Excluding cost of capital, the cost of designing and building a power plant for IGCC is currently estimated to be about 20 percent higher than PC systems, and commercial reliability has not yet been well established (Rosenberg et al., 2005). The combined cycle portion of the process is attractive from a capital cost perspective compared to a conventional coal plant, but the addition of gasification, coal feed equipment, gas cooling, gas cleanup, and the installation of an oxygen plant result in an overall cost that is higher than a conventional coal plant. The resulting higher efficiency as compared to a conventional coal plant cannot offset the higher capital costs. The currently demonstrated capital cost is about 30 percent higher and the efficiency is approximately five percent better than a conventional coal plant. This cost and performance comparison does not result in a cost of electricity that is lower than a conventional coal plant (Dalton, 2004).

As a result, investments to design and build commercial IGCC power plants in the U.S. have not yet materialized on a large scale due to cost and risk concerns. A 2004 survey by DOE indicates that the three leading risk factors perceived by industry to be associated with IGCC investments are high capital costs, excessive down time, and difficulty with financing (Rosenberg et al., 2005). The U.S. Department of Energy is continuing to fund research and development of IGCC, focusing on improvements in efficiency, fuel flexibility, and economics (DOE, 2005j).

Because IGCC technology currently is not cost-effective and requires further research to achieve an acceptable level of reliability, an IGCC facility is not a reasonable alternative for meeting the projected energy needs of SME. Furthermore, with the exception of IGCC’s yet undeveloped potential for removal of CO_2, IGCC does not demonstrate significant overall advantages compared to a CFB facility for key air pollutants, including mercury.

2.1.5.5 Oil

In the United States as a whole, electricity generated by oil or petroleum (including distillate fuel oil, residential fuel oil, petroleum coke, jet fuel, kerosene, other petroleum and waste oil) has declined substantially in recent decades. From a peak of 365 million MWh in 1978 (17 percent of total U.S. net electricity generation in that year), petroleum accounted for just 118 million MWh – three percent – of net electricity generated in 2004 (EIA, 2005f). With the peak of domestic petroleum production in 1970, rising imports since then, increasing global prices over the last few years and the prospect for more of the same, plus competition for this valuable fuel commodity not only from the transport sector but also from the petrochemical industry, it is virtually certain that the downward trend for using petroleum to generate electricity will continue.

Three technologies are used to generate electricity from oil:

- *Conventional steam* - Oil is burned to heat water and create steam to generate electricity;
- *Combustion turbine* - Oil is burned under pressure to produce hot exhaust gases which spin a turbine to generate electricity;
- *Combined-cycle technology* - Oil is first combusted in a combustion turbine, using the heated exhaust gases to generate electricity. After these exhaust gases are recovered, they heat water in a boiler, creating steam to drive a second turbine (this is the NGCC process described in Section 2.1.5.1) (PowerScorecard, 2005).

Oil, like coal, is a fossil fuel, and burning it emits most of the same air pollutants as burning coal, though in different quantities. Oil combustion for electricity generation produces air pollutants such as nitrogen oxides, volatile organic compounds, and particulates, as well as, depending on the sulfur content of the oil, sulfur dioxide. Electricity from oil also results in emissions of the greenhouse gases carbon dioxide and methane and heavy metals such as mercury (PowerScorecard, 2005).

The looming peak of global oil production – whether in the current or an upcoming decade – presents the United States and the entire world with an unprecedented challenge in risk management. As the peak is approached – at the same time that global demand for oil is still increasing steadily in developed countries like the U.S. but now also increasing sharply to fuel the industrial development of rapidly growing, heavily populated countries like China and India – liquid fuel prices and price volatility will increase dramatically. Without timely mitigation, the economic, social, and political costs could be unprecedented (Hirsch et al., 2005). Skyrocketing gas prices and price volatility are much on the minds of Americans consumers and motorists even today each time they pull up to a gasoline station.

Important observations and conclusions from a 2005 U.S. Department of Energy-funded study (Hirsch et al., 2005) on the implications of "peak oil" include:

1. When the peak of world oil production will occur is not known with certainty. A fundamental problem in predicting oil peaking is the poor quality of and possible political biases inherent in world oil reserves data. (In the 1980s many member states of the Organization of Petroleum Exporting Countries (OPEC) cartel arbitrarily boosted their stated reserves in order to capture higher production quotas. These stated "political" reserves must be regarded with skepticism.) Some experts believe peaking may occur soon. The 2005 DOE study indicates that "soon" is within 20 year, while some authorities believe peaking may even occur before 2010.
2. The problems associated with world oil production peaking will not be temporary but rather, long-lived. Therefore, past "energy crisis" experiences, which were temporary (e.g., 1974-75 during the Arab Oil Embargo and 1979-80 due to the Iranian Revolution), will provide limited guidance. The challenge of peak oil deserves immediate, serious attention, if risks are to be fully understood and mitigation initiated on a timely basis.
3. Oil peaking will create a severe liquid fuels problem for the transportation sector, not an "energy crisis" in the usual sense that term has been used.
4. Peaking will result in dramatically higher oil prices, which will cause protracted economic hardship in the United States as well as the world. However, the problems are not insoluble. Timely, aggressive mitigation initiatives addressing both the supply and the demand sides of the issue will be required.
5. In the developed nations, the problems will be especially serious. In the developing, less affluent nations, peaking problems have the potential to be even worse.
6. While greater end-use efficiency in the use of oil is essential, increased efficiency alone will be neither sufficient nor timely enough to solve the problem. Production of large amounts of substitute liquid fuels will be required. Various commercial or near-commercial substitute fuel production technologies are currently available for deployment, so the production of vast amounts of substitute liquid fuels is feasible with existing technology.
7. Intervention by governments will be required, because the socioeconomic implications of peak oil and the post-peak oil period would otherwise be chaotic. The experiences of the 1970s and 1980s offer some guidance as to government actions that are desirable and those that are undesirable, but the process will not be easy (Hirsch et al., 2005).

In conclusion, no one has built or is contemplating building oil-fired plants in recent years because of their high and increasing cost and, as compared to natural gas, greater air emissions, thereby requiring additional air pollution controls. In terms of SME's need to generate affordable electricity for its members and customers, oil would not be a cost-effective alternative, and thus is not evaluated any further in this EIS.

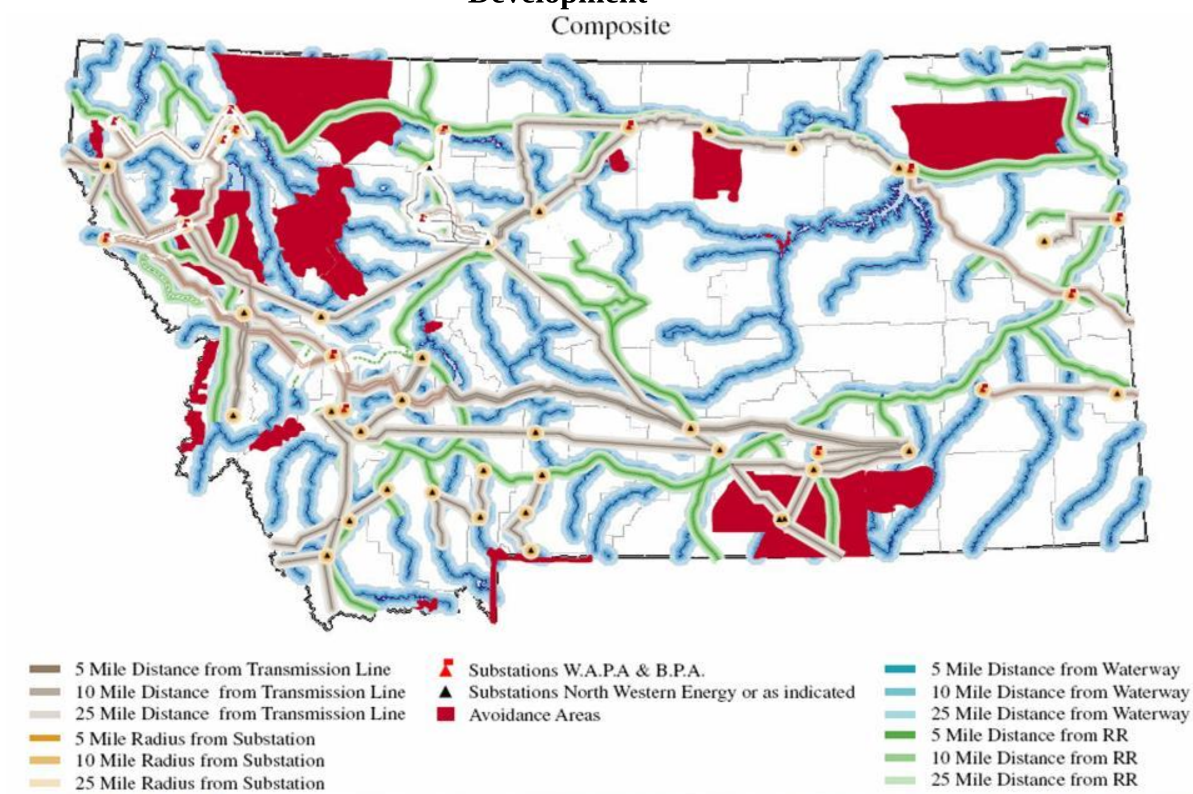
2.1.6 OTHER COAL-FIRED POWER PLANT SITES

In 2004, Stanley Consultants, Inc. performed a study (SME, 2004b) focusing on the major factors that affect site selection for a coal-fired power plant, including: environmental impacts and the cost of mitigation; relative costs of site development, and projected production costs. In particular, the study compared potential generating sites in terms of:

- Heat rate, which considered the different types of coal and locations at which the coal would be utilized;
- Water consumption and wastewater discharge, including source and discharge points, and associated water rights issues;
- Environmental suitability, which includes the existing land use, air quality concerns, proximity to state or national parks and wildlife areas, existing or planned airports, and Native American lands;
- Site-specific costs for plant development and operation;
- Infrastructure improvements for both construction and operation, which included roads, railroads, water and natural gas pipelines, and transmission; and
- Cost and schedule benefits and impacts.

On behalf of SME, Stanley Consultants initially screened the entire state of Montana, identifying prospective power plant sites that were generally close to water bodies, transmission lines, substations, and railroads while at the same time avoiding Native American lands and Class I airsheds (national parks and national wilderness areas) (SME, 2005d). Figure 2-17 reveals a composite screening map of the state of Montana which identified these features.

Figure 2-17. Composite Map of Montana Depicting Features Relevant for Power Plant Development



Source: SME, 2005d

Several site-specific risks were identified with the potential to impede, delay or prevent development of the plant at a given site. These risks include:

- Ability to obtain air quality permits
- Ability to obtain Montana Pollutant Discharge Elimination System (MPDES) permit
- Ability to obtain other water permits
- Ability to obtain solid waste permits
- Availability of fuel supply
- Water resources required for operation
- Availability of transportation infrastructure
- Availability of transmission lines and the feasibility of interconnection

Four main sites emerged from the initial screening process: Salem (including the sites identified as Salem and Salem Industrial or Industrial Park sites), Decker, Hysham, and Nelson Creek. Their locations are shown in Figure 2-18. An artist's rendering of a power plant at each site is depicted in Figure 2-19.

Based on the results of the site selection study, the Salem and Industrial Park sites (Sections 2.2.2 and 2.2.3 in this EIS, respectively) are considered reasonable locations for the proposed generating station. The Decker, Hysham, and Nelson Creek sites were judged to be unacceptable with respect to one or more of the factors summarized above, and, therefore, they are not analyzed in detail in this EIS. The major activities and components associated with construction of a 250-MW plant at each of these three sites are described in the following sections.

Figure 2-18. Locations of Four Main Potential Sites in the Site Screening Study

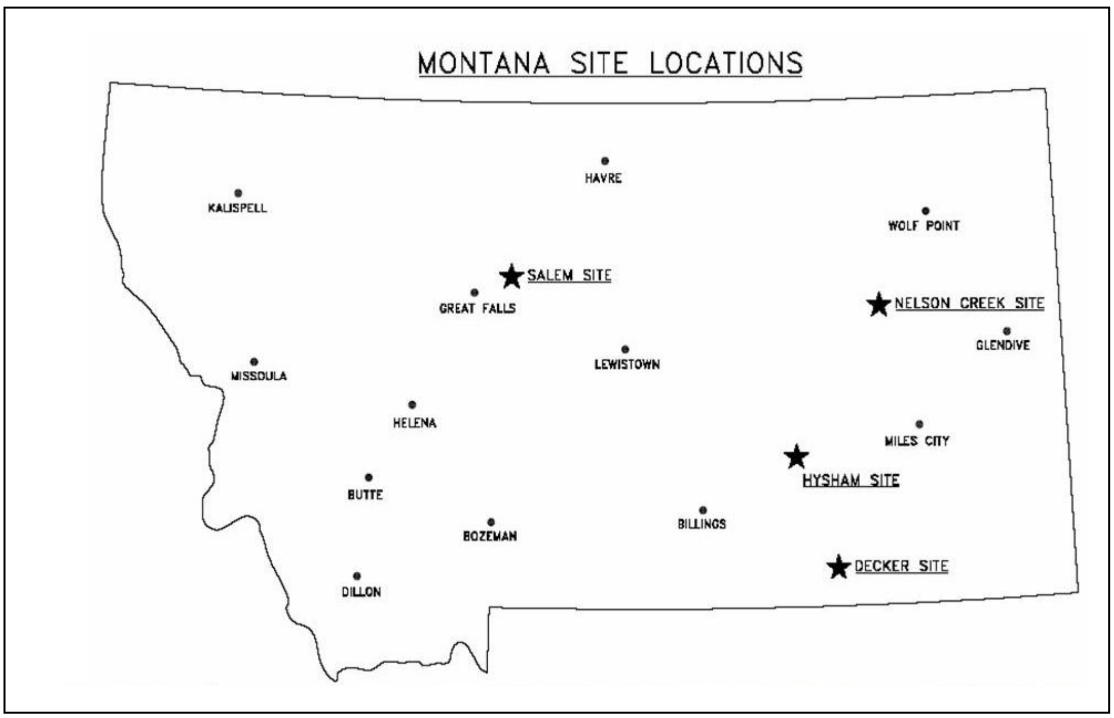
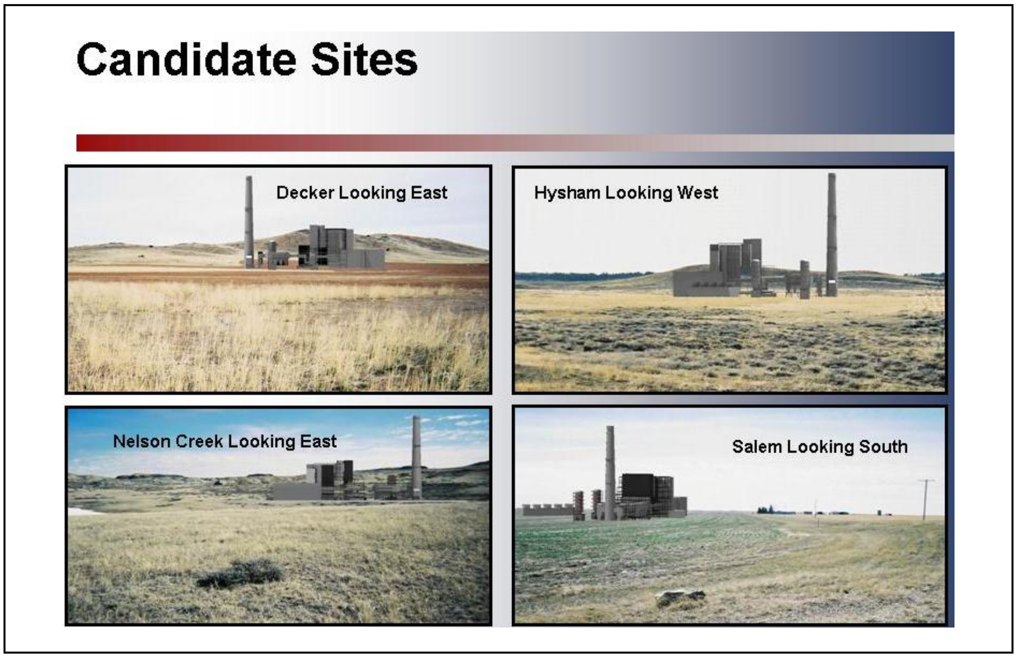


Figure 2-19. Artist's Renderings of a Coal-Fired Power Plant at the Four Candidate Locations



2.1.6.1 Decker

The Decker site is situated at an elevation of approximately 3,881 feet (1,183 m) above sea level, 30 miles (48 km) east of Interstate 90 and east of Highway 314 near the North Fork Monument Creek. The Decker site is in the Southwest ¼ of Section 1, Township 8 South, Range 39 East.

A generating station at the Decker site would consume an estimated 251,400 lb/hr (1,101,200 tons/yr) of sub-bituminous coal supplied by railroad from the Decker Mine. Four miles (6.4 km) of new track and railroad bed would be required from the existing Burlington Northern Santa Fe (BNSF) Railroad main line track system to the plant site.

Make-up water would be pumped from an intake structure on the west bank of the Tongue River Reservoir for a distance of about 11 miles (18 km) to the plant. This location is served by the smallest watershed of any of the sites. This stream appears to be heavily allocated. Average daily flow at the Tongue River dam during 2002 (a dry year) was 136 cubic feet per second. Allocations and claims on file total more than the average daily flow such that many junior users received less water than they wanted or were cut off during that time (SME, 2004b).

No.2 fuel oil would be delivered to the plant by truck for start-up. Limestone and ammonia would be delivered to the facility by railroad. Approximately 6,420 lb/hr (28,200 tons/yr) of limestone and 50 lb/hr (220 tons/yr) of ammonia would be consumed. About 10,300 lb/hr (45,150 tons/yr) of ash waste would be produced and trucked back to the Decker Mine for disposal (SME, 2004b).

Electricity produced at the plant would be transmitted to the existing Rosebud Substation and would require approximately 80 miles (129 km) of new transmission line. The plant at the Decker site would also interconnect with a new Tongue River Substation, which would be located east of the existing Colstrip Power Plant (SME, 2004b).

The Decker site was more expensive than either of the Salem sites and was also judged to have a higher degree of risk associated with environmental permitting and approvals, was subject to water disruption and the lack of available water rights, and was therefore eliminated from further consideration (SME, 2004b).

2.1.6.2 Hysham

The Hysham site is in the Southwest ¼ of Section 11, Township 6 North, Range 37 East. The site is approximately 2,879 feet (878 m) above sea level and is located about eight miles (13 km) south of the Yellowstone River on the west side of Old Sarpy Road (refer to Figure 2-20) . It was formerly a gravel borrow site.

Figure 2-20. Looking West onto the Yellowstone River Near the Hysham Candidate Site

A generating station at the Hysham site would consume about 280,800 lb/hr (1,230,000 tons/yr) of sub-bituminous coal supplied by railroad from the Absaloka Mine (SME, 2004b). About 1.5 miles (2.4 km) of new track and railroad bed would be required from the existing BNSF Railroad main line track system to the plant site.

Make-up water would be pumped from an intake structure on the Yellowstone River, east of the City of Hysham, for about nine miles (6.4 km) to the plant. According to Montana Department of Natural Resources and Conservation (DNRC), much of the available water from the Yellowstone River is already allocated. An off stream storage structure, or arrangement, would most likely be necessary to guarantee the necessary flow (SME, 2004b).

Natural gas would be supplied to the plant for start-up fuel from an existing pipeline. Limestone and ammonia will be delivered to the facility by railroad. About 13,240 lb/hr (58,000 tons/yr) of limestone and 50 lb/hr (220 tons/yr) of ammonia would be consumed. Approximately 26,030 lb/hr (114,000 tons/yr) of ash waste would be produced and trucked to a landfill location on site (SME, 2004b).

Electricity produced at the plant would be transmitted to the existing Rosebud and Custer Substations. Approximately 34 and 53 miles (55 and 85 km) of new transmission line would be required to the Rosebud and Custer Substations respectively (SME, 2004b).

As in the case of the Decker site above, the Hysham site was more expensive than either of the Salem sites and was also judged to have a higher degree of risk associated with environmental permitting and approvals and available water supply and water rights. Therefore it was eliminated from further consideration (SME, 2004b).

2.1.6.3 Nelson Creek

The Nelson Creek site is in the Northwest ¼ of Section 36, Township 21 North, Range 43 East. The site is located southeast of Nelson Creek Bay, just east of Highway 24, at approximately 2,322 feet (708 m) above sea level.

A generating station at the Nelson Creek site would consume an estimated 371,400 lb/hr (1,626,800 tons/yr) of lignite coal supplied from a new mine located east of the plant. The coal would be delivered by heavy-haul mine trucks a distance of two miles on existing roads to the plant. It is estimated that over 45 miles (72 km) of existing railroad track from Glendive to Circle would need to be upgraded to accommodate the delivery of major equipment, and about 26 miles (42 km) of road improvements would be needed to transport major equipment by heavy-rigging trucks from the upgraded rail siding at Circle to the site.

Make-up water for the plant would be pumped from an intake structure located on Fort Peck Reservoir. A 41-mile (66-km) pipeline would be needed to supply the water to the plant. However, according to the DNRC, the Corps of Engineers has filed several water right claims for amounts approximating the capacity of the Fort Peck reservoir (SME, 2004b).

No.2 fuel oil would be delivered to the plant by truck for start-up. Limestone and ammonia would be delivered to the facility by trucks. Approximately 9,730 lb/hr (42,700 tons/yr) of limestone and 82 lb/hr (360 tons/yr) of ammonia would be consumed. About 26,930 lb/hr (117,950 tons/yr) of ash waste would be produced and trucked back to the new mine for disposal (SME, 2004b).

Electricity produced at the plant would be transmitted to the existing Rosebud and new Tongue River Substations. Ninety miles (145 km) of new transmission line would be required from the plant to the Rosebud Substation (SME, 2004b).

As with both the Decker and Hysham sites above, the Nelson Creek site was determined to be more expensive than either of the Salem sites and was also deemed to have a higher degree of risk associated with environmental permitting and approvals and available water supply and water rights. Therefore it was eliminated from further consideration (SME, 2004b).

2.1.7 Salem Site Alternatives Dismissed

Five other alternative components at the preferred Salem site were considered and dismissed from more detailed consideration in the EIS.

2.1.7.1 Obtaining Potable Water from Other Sources

Potable or drinking water could be provided via imported bottled water, by drilling a groundwater well, or by installing a treatment system in order to use additional diverted Missouri River water as the drinking water source for the plant.

- Importing bottled water is an option to supply drinking water at the site and individual offices and staff may select to have bottled water dispensers available. However, bottled water would not be an option for supplying water for restrooms, outdoor faucets for watering lawn areas, and other non-industrial water uses. Bottled water would not be cost effective in large quantities for site-wide use for anything other than drinking water.

- Potable water for the HGS power plant could be obtained from one or more drinking water wells drilled on-site. SME rejected this alternative in part because of the 300-450-foot depth to the water-bearing Madison limestone formation (PBSJ, 2005). There are ample groundwater sources in the area of the site although not readily available and requiring a deep well. Some pretreatment of the water may be required in order to meet federal and state drinking water standards. The water treatment facility would be classified as a public water supply and would be subject to state and county regulations. The operator of this facility would have to be licensed by DEQ.

- An additional river diversion could be used to obtain potable water for the HGS or the industrial diversion could be upgraded to handle the additional volume of water. The river water would most likely require some pretreatment in order to meet federal and state drinking water standards. The water treatment facility would be classified as a public water supply and would be subject to state and county regulations. The operator of this facility would have to be licensed by DEQ.

Construction of a 20 gallons per minute water treatment facility would result in additional disturbance of soils and plants at the facility location. Depending upon the type of water treatment method selected (reverse osmosis, ion exchange, etc.), additional chemicals or reagents may be needed which could in turn result in waste streams that must be selectively handled for disposal, such as the brine generated from a reverse osmosis facility. There would be a slight increase in traffic to the plant from the delivery of the needed chemicals and reagents, and the removal of waste products. The treatment facility may also require large quantities of electricity to operate as these are not passive systems. This alternative could cost anywhere from $250,000 to $750,000 to construct (approximate capital costs) and as much as $20,000 to operate each year, depending upon the treatment method selected. There would be annual operation and maintenance costs in addition to the need to hire licensed operators

Although obtaining potable water from a groundwater well or the Missouri River are feasible alternatives, they offer no environmental benefit over SME's Proposed Action to obtain potable water from the City of Great Falls. Either of these alternative sources would be available to SME as a contingency should it be unable to obtain water from the city. Since the construction and location of the raw water intake and pipeline are already analyzed in this EIS, DEQ would only need to analyze the impacts from the construction and operation of the public water treatment facility as required by state law (75-6-101 *et seq.*, MCA and ARM 17.38.101 and 102).

2.1.7.2 Discharging Wastewater into the Missouri River

This alternative would consist of discharging treated wastewater or effluent directly from the HGS into the Missouri River. SME would need to obtain an MPDES permit with wastewater parameter conditions or criteria from DEQ. SME rejected this alternative in favor of discharging into the City of Great Falls' wastewater treatment system on the grounds of environmental benefits, the cost to construct, operate, maintain, and monitor the facility, and the convenience of hooking into an existing permitted wastewater treatment and disposal facility. This alternative could cost anywhere from approximately $750,000 to $1,000,000 to construct and approximately $100,000 to operate each year depending upon the treatment method selected.

Construction of the plant would result in additional disturbance of soils and plants at the plant location. There may be some impacts to aquatic life downgradient of the discharge, although they would not be significant as long as the discharge complied with MPDES permit limits. In addition to operating costs, the facility must be maintained and effluent inflow and outflow must be monitored to ensure the discharge would comply with the MPDES permit.

Discharging treated industrial wastewater into the Missouri River from the HGS is a feasible and reasonable alternative. However, given the capacity of the City of Great Falls wastewater treatment facility (see Proposed Action description in Section 2.2.2.2 below), there are no additional environmental benefits associated with the construction, operation, maintenance, and monitoring of an on-site wastewater treatment facility and discharge into the river.

2.1.7.3 Disposal of Sanitary Wastewater in Septic System

Disposing sanitary wastewater in a septic system was reviewed as an alternative to including it in the wastewater stream proposed to be sent to the City of Great Falls wastewater treatment facility or with wastewater discharged to the Missouri River from the plant site in accordance with an MPDES permit as described above. Under state law, this system would qualify as a public sewer system (75-6-101 *et seq.*, MCA and ARM 17.38.101 and 102), and the operator of this facility would have to be licensed by DEQ. SME would be required to submit plans to DEQ or a delegated division of local government for review and approval.

Construction of a sewer system would result in the disturbance of additional soils and vegetation for the treatment facility and the septic field. There would be some limited potential for seepage from the septic field to reach groundwater. There would be annual operation and maintenance costs in addition to the need to hire licensed operators.

Although a public sewer system is a feasible alternative, it offers no environmental benefits over SME's proposed connection and use of the City of Great Falls wastewater treatment for disposal and treatment of sanitary wastes.

2.1.7.4 Alternate Railroad Spur Alignments

Three possible rail spur alignments were evaluated for cost, environmental impacts, impacts to land owners, and impacts to residents of the City of Great Falls. The two alternate routes were eliminated from further consideration.

- The railroad spur could be routed south from the power plant to the abandoned railroad grade, then placed along this railroad grade toward the city of Great Falls and tied into existing track north of Malmstrom Air Force Base. This alternate route would be 8.6 miles (13.9 km) long – 2.3 miles (3.7 km) longer than the proposed alignment. A short portion of the abandoned railroad grade immediately north of Malmstrom Air Force Base has been converted into a construction and demolition waste landfill and is no longer on grade; the spur would have to avoid this landfill. Other disadvantages include: the necessity of reworking and replacing sections of the existing, abandoned railroad grade to comply with modern standards; a route that would divide certain privately owned croplands against the wishes of their owners; and routing HGS-related coal train traffic through the City of Great Falls, about which some residents have expressed concerns about wait times at existing at-grade street crossings.
- The railroad spur could be routed north from the power plant and towards the city of Great Falls along property lines. This alternate route would also tie into the existing track north of Malmstrom Air Force Base. This route would be 8.5 miles (13.7 km) long – 2.2 miles (3.5 km) longer than the proposed alignment. Other disadvantages include: difficult and expensive installation due to the rough terrain that would be crossed; greater environmental impacts at crossings of coulees and watercourses; and the highest estimated cost due to the large structures (either bridges or trestles) that would be needed.

These two alternate railroad spur alignments would provide no beneficial advantage over SME's proposed route, and were therefore, eliminated from further consideration.

2.1.7.5 Hauling Ash to the High Plains Landfill

SME investigated hauling ash to the High Plans Landfill (see Figure 2-23) rather than storing the ash in a monofill on site. This alternate method of disposing of this material would require approximately 10-12 trucks per day to be hauled through the City of Great Falls along S-228 and U.S. 87. The hauling of the ash would add to the wear and tear and required maintenance of the city and county roads used en route to and from the HGS at the Salem site. SME would either be required to maintain a fleet of trucks or hire a firm to haul the material resulting in creased costs of approximately $180,000-$220,000 per year to haul the ash to the High Plans landfill. Given that SME and DEQ believe that the bedrock beneath the proposed facility and the compacted clay liner would minimize downward migration of contaminated water into the ground water there would be no beneficial advantage to hauling the ash approximately 25 miles (40 km) one-way to the landfill.

2.1.8 CONCLUSION

The projected levelized costs for new utility power generation plants in the Montana area are documented in Table 2-8. The power-generation technologies presented with their respective competitive costs are wind, solar, hydroelectric, geothermal, biogas, MSW, NGCC, microturbines, PC, CFB and IGCC. Wind, solar, and hydroelectric power have average capacity factors which range from 26 to 50 percent and cannot be considered for base load service.

A comparison of the alternate technologies regarding their capability of meeting the SME purpose and need criteria is documented in Table 2-9. Only the PC and CFB coal technologies are capable of meeting all of the criteria. NGCC offers the average capacity factor SME requires and the capital cost component of the levelized cost of NGCC power is attractive as compared to a CFB or pulverized coal plant. However, the volatility of natural gas prices results in NGCC being a costly option for SME's member cooperatives and customers.

The alternative of using oil as a fuel source, not displayed in Tables 2-8 and 2-9, was rejected on the basis of high current and probable future fuel costs as demand for this commodity continues to increase globally and supplies become more limited or insecure.

CFB has been selected as the preferred technology which would satisfy the projected SME base load needs due to its combination of environmental, economic, and technical advantages over other alternatives. The summary analysis of the Decker, Hysham and Nelson Creek sites above assumed the construction and operation of a CFB coal-fired power plant at each location. These sites advanced through the initial screening process but were rejected in favor of the two Salem sites (Salem and Industrial Park) on the basis of both economic and environmental factors (such as available water). In the following sections, the Salem and Industrial Park sites are described, along with the No Action Alternative.

Two project alternatives at the Salem Site – obtaining potable water from aquifers rather than the City of Great Falls municipal drinking water system, and discharging treated wastewater into the Missouri River rather than the City of Great Falls' municipal wastewater collection and treatment system – were rejected on the basis of greater convenience and environmental advantages as well as lower cost.

Table 2-8. Levelized Costs for New Utility Power Generation Plants in Montana

Type of Power Plant	Levelized Costs ($mWh)				
	Capital Cost	Fixed O&M Cost	Variable / Fuel Cost	Total Busbar Cost[1]	Average Capacity Factor
Wind	35.9	7.7	7.0[2]	50.6	26%-36%
Solar – Photovoltaic	N/A	N/A	N/A	350.0	20%-35%
Solar – Thermal	N/A	N/A	N/A	105.0	20%-35%
Hydroelectric	17.0	2.6	4.0	23.6	40%-50%
Geothermal	N/A	N/A	N/A	65.0	90%
Biomass	N/A	N/A	N/A	90.0	90%
Biogas	37.0	6.6	3.0	46.5	90%
Municipal Solid Waste (MSW)	32.8	38.9	13.0	84.8	90%
Natural Gas Combined Cycle (NGCC)	19.0	2.3	41.0	62.3	90%
Microturbines	49.1	8.4	55.7	113.2	90%
Pulverized Coal (PC)	25.1	4.6	12.8	50.1	90%
Circulating Fluidized Bed Coal (CFB)	25.2	4.6	12.8	42.6	90%
Integrated Gasification Combined Cycle Coal (IGCC)	42.8	3.3	19.8	65.9	<80%

Source: SME, 2004a

Note:
[1] Busbar Cost – wholesale cost to generate power at the plant.
[2] Variable cost for wind power represents transmission costs
$/mWh – dollars per megawatt hour
O&M - operations and maintenance

Table 2-9. Comparison of Alternative Power Generation Technologies in Meeting the Purpose and Need of the Proposed Action

	Capable of Meeting Purpose and Need Criteria							
Type of Power Plant	250 mW in 2009	Baseload Operation	Environmentally Permitable	Cost-effective	Fuel Cost Stability	High Reliability	Commercially Available	Meets All Criteria
Wind	Yes	No	Yes	Yes	Yes	Yes	Yes	No
Solar -Photovoltaic	No	No	Yes	No	Yes	No	Yes	No
Solar-Thermal	No	No	Yes	No	Yes	No	Yes	No
Hydroelectric	No	No	Difficult	Yes	Yes	Yes	Yes	No
Geothermal	No	Yes	Yes	N/A	Yes	Yes	N/A	No
Biomass	No	Yes	Yes	No	Yes	Yes	Yes	No
Biogas	No	Yes	Yes	Yes	Yes	Yes	Yes	No
Municipal Solid Waste (MSW)	No	Yes	Difficult	No	Yes	No	Yes	No
Natural Gas Combined Cycle (NGCC)	Yes	Yes	Yes	Yes	No	Yes	Yes	No
Microturbines	No	No	Yes	No	No	Yes	Yes	No
Pulverized Coal (PC)	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Circulating Fluidized-Bed (CFB) Coal	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Integrated Gasification Combined Cycle Coal	Yes	Yes	Yes	No	Yes	No	Yes	No

Note:
Based on alternate power plant options located within or adjacent to the SME System.

2.2 ALTERNATIVES TO BE ASSESSED IN DETAIL

This section describes the alternatives that are considered reasonable and are analyzed in detail in this EIS. For an alternative to be judged reasonable, it must meet the purpose and need for proposing a new energy generation source for the SME service area, which is to provide wholesale electric energy and related services for the SME service area. Reasonable alternatives must be affordable, reliable, and stable sources of wholesale electric energy, and they cannot pose unacceptable environmental risks.

Several sites in the SME service area were evaluated in 2004 to determine their suitability for constructing a 250-MW CFB coal-fired power plant. Factors considered in assessing the sites were: relative costs of site development, projected production costs, environmental impacts and the cost of mitigation, the availability of an adequate source of water; movement of electrical power, the load centers for the member cooperatives, proximity to nearby fuel sources, and ability to obtain environmental permits. In addition to the No Action Alternative, this section describes the two sites that meet these criteria and are evaluated in detail in the EIS.

2.2.1 NO ACTION

Under the No Action Alternative, the Highwood Generation Station would not be constructed or operated to meet the projected 250-MW base load needs of SME. There would be no facilities constructed at either the Salem or Industrial Park sites to meet the purpose and need discussed in Chapter 1 of the EIS.

However, it is unreasonable to assume that no alternative source of electricity would be provided for SME customers once the current power purchase agreement with the Bonneville Power Administration begins to expire. Member cooperatives and consumers would not simply “do without.” Therefore, the primary assumption for the No Action Alternative is that the need for a reliable energy supply for the SME service area would still be met by some means. At the same time, the No Action Alternative needs to describe the consequences of taking the minimal action necessary to provide uninterrupted power. In that case, SME would not investigate other cost-effective and potentially reliable energy sources, nor would efforts be made to extend the current power purchase agreements.

At a minimum, however, SME would need to purchase power from existing sources of wholesale supply. As stated in Section 2.1.1, because of projected increased costs, SME estimates the price it would pay under new power purchase agreements could be as much as double its current costs (SME, 2004a). These increased costs would be passed on to SME’s residential, commercial and industrial customers. This action would also promote the continued use of existing generation sources which in many cases are inefficient coal sources with higher emissions than the proposed preferred action.

2.2.2 PROPOSED ACTION: HIGHWOOD GENERATING STATION – SALEM SITE

The Salem site is located in Section 36, Township 21 North, Range 5 East at about 3,354 feet (1,022 m) above sea level (Figures 2-21 and 2-22). It is east and north of the intersection of Salem Road and an abandoned railroad bed. Figure 2-23 depicts the two Salem sites in relation to each other, the Missouri River, and the City of Great Falls. Figure 2-24 depicts the preliminary arrangement of key facilities on the Salem site, while Figure 2-25 depicts relative and approximate heights, elevations and sizes of the main CFB plant features.

2.2.2.1 Construction

Construction is estimated to take approximately three and a half years (51 months) from the start of preliminary engineering to commercial operation of the plant. Construction would begin with site preparation, foundations, and underground utilities, while design of the above-ground mechanical, piping, buildings, structures, and electrical systems is being developed.

The existing aggregate roadways currently leading to the site would be used and maintained during construction. At the end of the construction period, these existing roadways would be regraded and covered with additional aggregate. A 1,800-ft (545-m) long paved access road into the site would be constructed and maintained from the existing Cascade County road, Salem Road. Additionally, 6,600 feet (2,000 m) of paved internal roadways would be constructed to facilitate both the construction and operations phases of the plant. These on-site, paved roads would be aggregate-based during construction and would be paved upon completion of heavy construction.

Site grading and preparation has a planned duration of approximately two months and would be followed by foundation construction, with a planned duration of approximately a year. Using a phased process, boiler and baghouse construction would commence approximately five months after the beginning of the foundation construction and would be completed in approximately two years. Once the foundation is complete, the installation of the turbine generator components would begin and be completed in one year. Construction activity is planned to occur over an approximate two years and seven months duration during which employment would average between 300 and 400 workers at any one time with an estimated peak construction workforce approaching 550 (Chaffee, 2005).

In order to supply coal to the HGS, it would be necessary to install a railroad spur. The spur would extend from one of the existing rail lines in the area to the plant site. SME selected one of the three possible rail spur alignments evaluated for cost, environmental impacts, impacts to land owners, and impacts to residents of the City of Great Falls .The spur would be routed south from the plant and tie into existing main line track that is located three miles (five kilometers) south of the city of Great Falls.

SME selected this alignment based on cost and minimizing environmental concerns. It has several advantages:

Figure 2-21. View of the Salem Site Looking Toward Highwood Mountains

Figure 2-22. Another View of the Salem Site

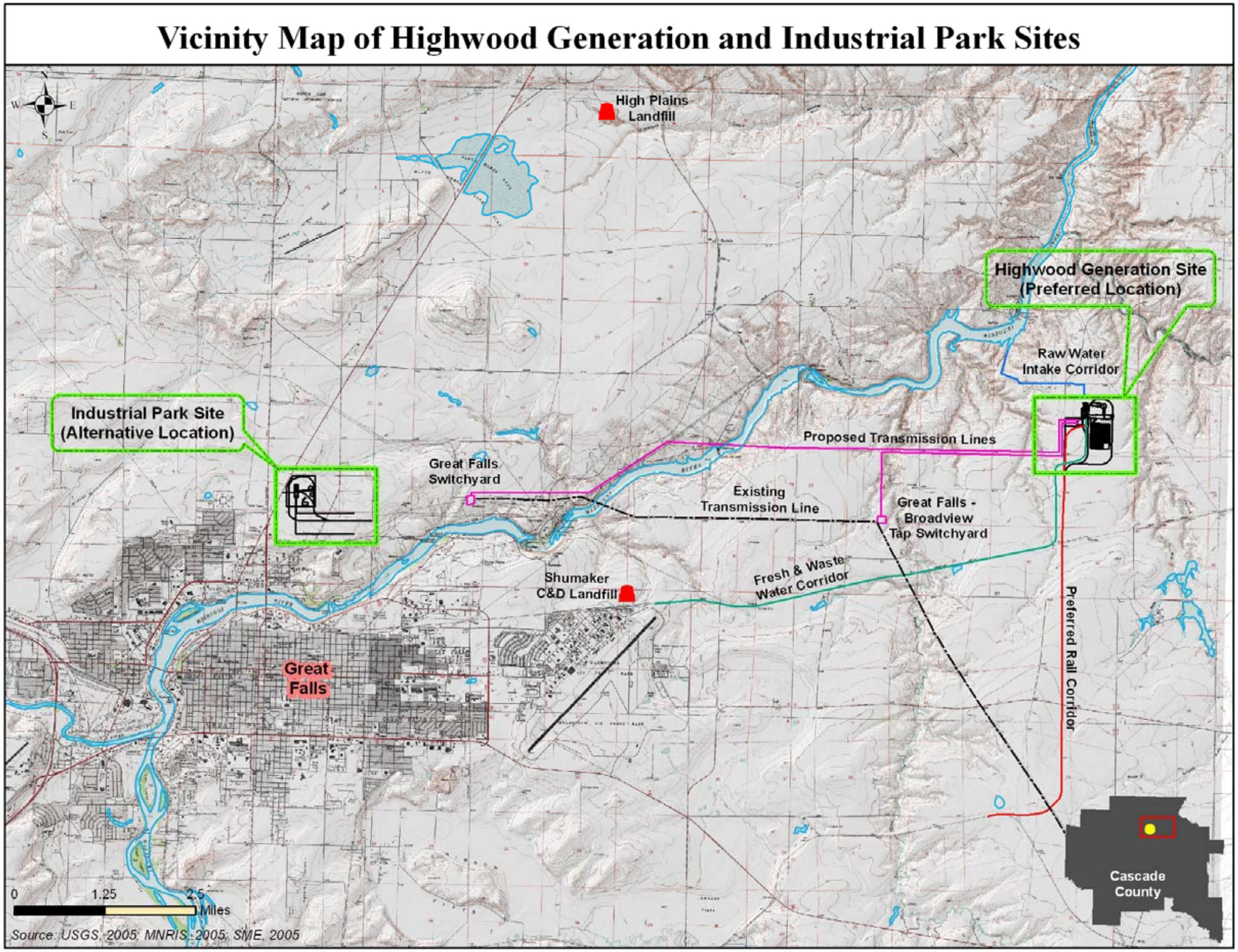
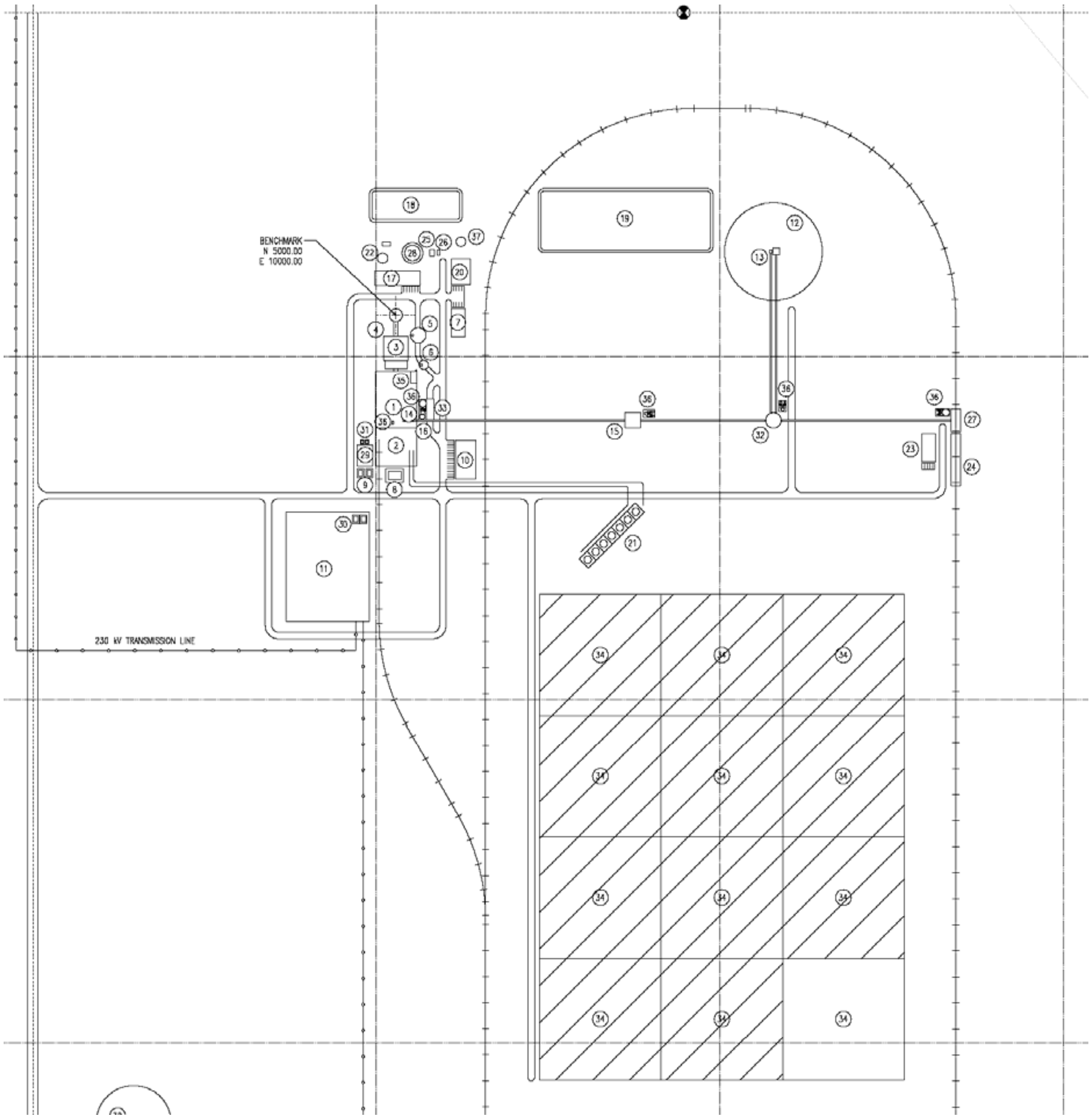


Figure 2-23. Vicinity Map of Highwood Generating Station (Salem and Industrial Park Sites), Great Falls, and Missouri River



NO.	DESCRIPTION
1	CFB BOILER
2	TURBINE BUILDING
3	BAGHOUSE
4	STACK
5	FLY ASH SILO
6	BED ASH SILO
7	AMMONIA STORAGE
8	GENERATOR STEP UP TRANSFORMER
9	AUXILIARY TRANSFORMERS
10	WAREHOUSE & ADMIN BUILDING
11	SWITCHYARD
12	COAL PILE STORAGE
13	RECLAIM HOPPER
14	LIMESTONE CRUSHER HOUSE
15	COAL CRUSHER HOUSE
16	LIMESTONE SILO
17	WATER TREATMENT BLDG
18	EVAPORATION POND
19	STORMWATER RUNOFF POND
20	WASTEWATER TREATMENT
21	COOLING TOWER
22	CLARIFIER
23	COAL HANDLING MAINT BUILDING
24	COAL CAR THAWING SHED
25	FIRE PUMP HOUSE
26	EMERGENCY GENERATOR
27	TRACK HOPPER
28	RAW WATER TANK
29	MAIN POWER DISTRIBUTION CENTER
30	START UP TRANSFORMERS
31	STATION SERVICE TRANSFORMERS
32	COAL SILO
33	LIME STONE UPLOADING STATION
34	ASH PILE
35	AUXILIARY BOILER
36	DUST COLLECTOR
37	DIESEL FUEL OIL STORAGE TANK
38	WIND TURBINE

Figure 2-24. Preliminary Site Configuration of the Highwood Generating Station

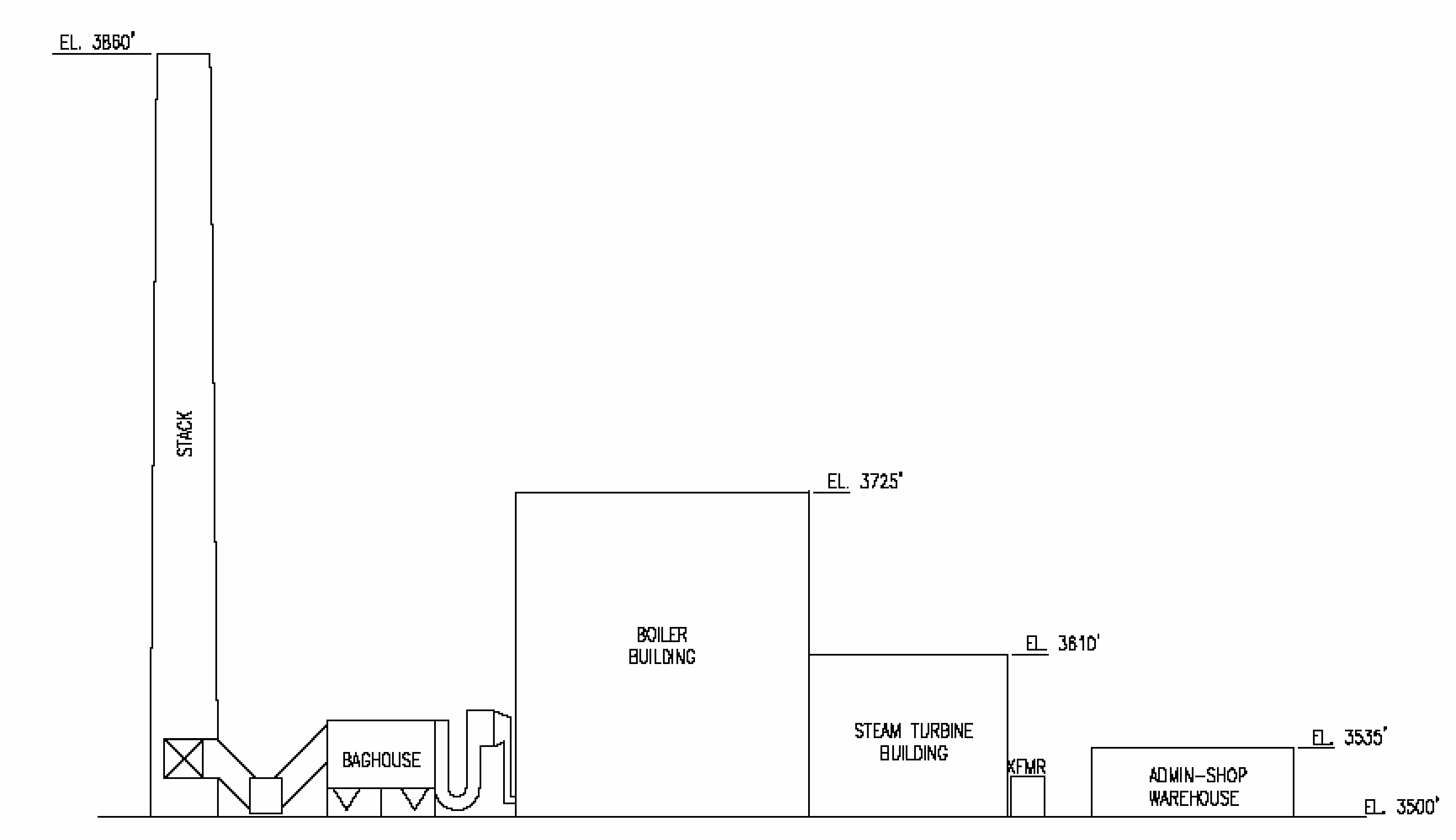


Figure 2-25. Relative and Approximate Heights, Elevations and Sizes of the Main CFB Plant Features (Preliminary)

- Shortest alignment at approximately 6.3 miles (10.1 km);
- No watercourse crossings required, which minimizes environmental impacts;
- Coal originates in southern Montana so the coal trains would be switched onto the spur resulting in no increase of train traffic in the City of Great Falls;
- Lowest estimated cost;
- No need to relocate construction and demolition waste landfill.

The two disadvantages of this route versus the other two options studied are that the tracks would cross Montana State Highway S-228, Highwood Road, which would require an expensive highway overpass, and it would cross agricultural land which would need to be reviewed with local property owners (SME, 2005e).

The HGS would require a reliable source of raw water for operations. The proposed water supply for both the primary and alternate sites is the Missouri River. The water rights for supplying the water would be from an existing water reservation that is owned by the City of Great Falls (City). The City would continue to own the water reservation and would sell the water to HGS through an agreement between the City and SME. However, the current points of diversion and places of use authorized under the existing water reservation do not include those required by the preferred HGS plant site. Therefore, the City has prepared and submitted an application to the Montana Department of Natural Resources and Conservation to add a point of diversion and place of use consistent with the preferred site (SME, 2005f).

Raw water for the preferred Salem HGS plant site would be obtained from the Missouri River approximately 0.4 mile (0.6 km) upstream of Morony Dam. Morony Dam is owned and operated by PPL Montana, a subsidiary of the former Pennsylvania Power & Light Company. The land directly adjacent to the reservoir is also owned by PPL Montana. Morony Dam is operated as a run-of-the-river generation facility. Therefore, the outflow is maintained essentially equal to the inflow. The Morony Reservoir (Figure 2-26) has a capacity of approximately 13,889 acre-feet and covers an area of approximately 304 acres (123 ha). Presently, there is no public access to the reservoir for recreational purposes.

Figure 2-26. Morony Dam and Reservoir at Site of Proposed Water Intake Structure

The raw water supply system would consist of a collector well which would use a passive intake screen installed on the end of a lateral pipe that extends into the Morony Reservoir. The intake screen would be located and designed to prevent sediment and debris from entering the system while also providing protection to aquatic life. The passive intake would be designed according to Section 316(b) of the Clean Water Act which applies to new cooling water facilities that withdraw between two and 10 million gallons per day (MGD). The rule states that the maximum throughscreen intake velocity must be less than 0.5 feet per second (fps).

A reinforced, below-grade, concrete caisson or sump (vertical cylinder) would be constructed near the river and would serve as the intake's "wet well." The caisson would be located outside of the floodplain. A fully enclosed pump house would be located on the top of the caisson with a finish floor elevation at approximately grade. The pump house would contain two pumps designed to deliver a maximum of 3,200 gallons per minute (gpm) to the plant site. The pumps would deliver the water to the HGS plant site through a buried pipe approximately 9,000 feet (2,740 m) long.

SME has options to obtain the necessary easements for the construction, operation and maintenance of the raw water system from the property owners. SME would also obtain needed permits from county, state, and federal regulators for the construction, operation and maintenance of the raw water system (SME, 2005f). On March 21, 2006 SME submitted a Joint Application to these the authorities, including DEQ and the Army Corps of Engineers.

If wastewater were to be discharged into the Missouri River, construction of a second discharge pipeline would be needed. However, the preferred option at present is to discharge wastewater back to the City of Great Falls for disposal at its existing waste water treatment facility. The wastewater would be transported via a 12" newly constructed sanitary force main that will run from the project site to a point near Malmstrom Air Force Base where the line will intersect an existing waste water line owned by the City of Great Falls. The length of the pipeline and main improvements will be approximately 55,000 feet (16,800 m). SME would need to obtain a permit from the City and meet pre-treatment effluent standards.

In order to export electrical power from the HGS it would be necessary to construct two short segments of 230 kV transmission line. The first line segment, approximately 4.1 miles (6.6 km) long, would extend from the plant site to a new 230kV switchyard site proposed for a location south and west of HGS. This terminus point coincides with an existing three pole wood deadend transmission structure on NorthWest Energy's (NWE) Broadview to Great Falls 230kV Transmission Line (EC, 2005). The proposed switchyard would consist of the following:

- 180 ft. by 240 ft. (55 to 73 m) fenced switchyard
- Standard 230 kV ring bus
- 230 kV switching equipment and related hardware
- Lightning protection
- Control house that will contain relaying and communications equipment.

The second line segment, approximately 9.2 miles (14.8 km) long, would extend south and west from the plant site, across the Missouri River north and east of Cochrane Dam and terminate at NorthWest Energy's existing Great Falls Switchyard, located north and west of Rainbow Dam.

Both line segments would be constructed in new rights-of-way typically extending 50 feet (15 m) either side of centerline. Single pole weathering (corten) steel pole structures would be utilized for the entire length of both lines except where necessary to cross the Missouri River. Multiple-pole or H-frame structures may be required at this crossing point to maintain proper phase-to-phase and phase-to-ground clearances.

All running angle and deadend structures would be supported by steel-reinforced concrete caisson foundations, eliminating the need for guys and anchors. All tangent structures would be direct embedded utilizing native or engineered soils as backfill. Structures are anticipated to vary in height between 80 and 100 feet (25-30 m) and would be constructed approximately every 500-700 feet (150-215 m) along the rights-of-way depending upon terrain and obstacles. Insulation would be provided by use of composite post and/or suspension insulators depending on the ultimate structure configuration chosen. The single circuit lines would consist of three 1272 kCM phase conductors protected by a single 3/8" (1 cm) EHS shield wire.

2.2.2.2 Operation

Once construction was completed, plant start-up activities would be initiated with a planned duration of eight months and must be completed before commercial operation of the plant could begin. Plant operation would employ approximately 65 permanent workers (DEQ, 2005).

The plant design consists of a CFB boiler, single re-heat tandem compound steam turbine, seven stages of feedwater heating, water-cooled condenser, wet cooling tower, hydrated ash reinjection or equivalent flue gas desulfurization (FGD) system, baghouse, and material handling system. Figure 2-23 depicts the general location of equipment including the boiler, turbine building, exhaust stack, coal yard, switch yard, cooling tower, and site roads. Figure 2-27 depicts the main elements of a CFB coal-fired power plant.

The plant would purchase sub-bituminous coal from either the Spring Creek or Decker mines in Montana's Powder River Basin (PRB), or other suitable supply from which comparable PRB coal supplies are produced. Coal consumption is estimated to be 300,000 lb/hr or 1,314,000 tons/yr, based on SME's air permit application. Coal would be delivered approximately twice a week in 110 bottom-dump rail car trains. The rail cars empty into a track hopper which feeds the coal to a transfer tower. The transfer tower moves the coal to either a coal silo or a storage pile. Feeders direct the coal from storage to the coal crusher building on two belts. The crushed coal is conveyed into one of four coal bunkers.

Limestone and ammonia would be purchased and utilized to reduce air pollutants. Limestone would be consumed at a rate of approximately 5,780 lb/hr or 25,300 tons/yr. Limestone would be delivered to the plant by truck from the Graymont Lime Plant and limestone quarry near Townsend, Montana. The bottom-dump trucks would empty their loads into a hopper, which feeds the limestone to a storage silo. From there the limestone would be crushed to reduce its size. The crushed limestone would then be transported to the CFB boiler to be utilized in the coal burning process.

Ammonia would be consumed at a rate of 239 lb/hr (1047 tons/yr), according to SME's air permit application. Anhydrous ammonia would be purchased and delivered to the plant by rail or by truck. The ammonia would be pumped from a rail unloading station from the rail car or truck to a horizontal storage tank. The ammonia would then be pumped from the storage tank to

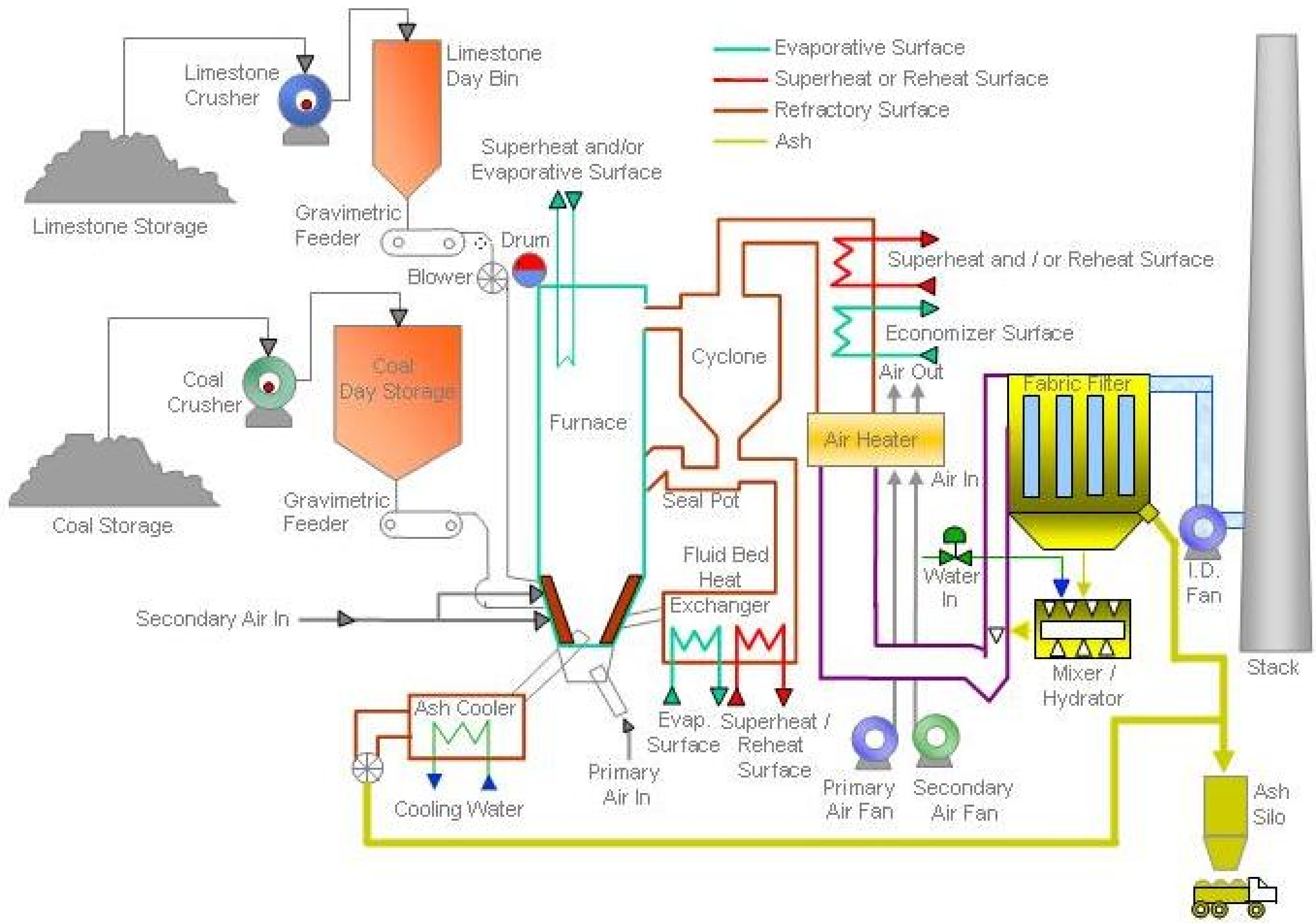


Figure 2-27. Circulating Fluidized Bed (CFB) Process with Hydrated Ash Reinjection*

*This figure represents a generic CFB process schematic. Reference to any individual component's inclusion or exclusion is determined on a project by project basis.

a vaporizer skid where steam is used to evaporate the liquid ammonia. Vaporized ammonia leaves the vaporizer and mixes with dilution air prior to injection into the boiler as a reagent for reducing NOx. System design safety features include separation distances, leak detection, spray and fogging systems, shower and eyewash stations, and containment barriers.

The facility power output rate is estimated to be a nominal 270 MW gross (250 MW net). It would be a low-emitting facility as a direct result of the application of state-of-the-art air pollution control technologies. The facility is designed to minimize environmental impacts and has incorporated environmental systems and equipment into the design of the facility (SME, 2005g).

The primary source of emissions to the atmosphere from the proposed generating station would be the CFB boiler (Figure 2-27). The CFB boiler itself, a “clean coal” technology, is an integral part of the proposed pollution control systems. By operating at lower temperatures, a CFB boiler generates lower NOx emissions than a comparable pulverized coal boiler. The CFB design also injects limestone into the boiler for control of SO_2 emissions and acid gas emissions (e.g. sulfuric acid or H_2SO_4 mist). Larger particles of unburned boiler bed material (coal and limestone) are separated in a cyclone from the boiler flue gas stream and “circulated” back into the CFB boiler. This circulation of unburned or heavy material provides for complete combustion of the coal and longer limestone residence times for more efficient collection of pollutants.

In addition to emission controls inherent in the CFB boiler design, SME proposes to install a fabric filter baghouse to reduce potential emissions of PM and PM_{10}. Potential NOx emissions would be further reduced using selective non-catalytic reduction (SNCR) technology and additional SO_2 and acid gas polishing would be accomplished using a hydrated ash reinjection (HAR) or FGD system (refer to Figure 2-27). The use of best combustion practices would limit emissions of CO and VOC. Table 2-10 provides a summary of the proposed emission control systems and projected emission rates for PSD pollutants from the facility as presented in the draft air quality permit from DEQ (DEQ, 2006a). The draft air quality permit is subject to comment from the public, including SME, and may change depending on such comments.

Other potential sources of air pollution from the generating facility include an auxiliary boiler, cooling tower, materials handling (e.g. coal, ash, and limestone), coal thawing shed heater, emergency coal storage pile, ash landfill, truck traffic, building heaters, fuel oil storage tank, emergency generator, and emergency fire water pump. SME would integrate mist eliminators into the cooling tower design, incorporate conveyor enclosures and baghouse dust collectors into the materials handling system design, use water and/or chemical dust suppression on the facility roadways, and use Best Management Practices (BMPs) on the emergency coal storage pile.

Overall estimated annual potential emissions of air pollutants of interest from all operations combined (including boiler and baghouse emissions, coal unloading and storage, etc.) at the proposed HGS are documented in Table 2-11.

Table 2-10. Best Available Control Technology (BACT) for proposed CFB at HGS

Pollutant	Proposed Annual Emission Limit	Proposed BACT Technology
NOx	0.07 lb./MMBtu	CFB Boiler and Selective Non-Catalytic Reduction
SO_2	0.038 lb./MMBtu	CFB Boiler with Limestone Injection and Hydrated Ash Reinjection/FGD
PM_{10} (filterable)	0.012 lb./MMBtu	Fabric Filter Baghouse
PM_{10} (condensable)	Included in the PM_{10} (total) limit	CFB Boiler with Limestone Injection, Hydrated Ash Reinjection/FGD, and Fabric Filter Baghouse
PM_{10} (total)	0.026 lb./MMBtu	CFB Boiler with Limestone Injection, Hydrated Ash Reinjection/FGD, and Fabric Filter Baghouse
CO	0.10 lb./MMBtu	Proper Boiler Design and Operation
VOC	0.003 lb./MMBtu	Proper Boiler Design and Operation
Sulfuric Acid Mist	0.0054 lb./MMBtu	CFB Boiler with Limestone Injection, Hydrated Ash Reinjection/FGD, and Fabric Filter Baghouse
Mercury	1.5 lb./trillion Btu	CFB Boiler with Limestone Injection, Hydrated Ash Reinjection, and Fabric Filter Baghouse

Source: DEQ, 2006a; MMBtu = Million British Thermal Units

Table 2-11. Estimated Potential Annual Emissions of Key Air Pollutants from Proposed HGS

Pollutant	Emissions in tons
Nitrogen Oxides (NOx)	847
Sulfur Dioxide (SO_2)	443
Carbon Monoxide (CO)	1161
Volatile Organic Compounds (VOCs)	35.6
Particulate Matter (PM)	373
Particulate Matter smaller than 10 microns (PM_{10})	363
Lead (Pb)	0.3
Mercury (Hg)	0.02

Source: DEQ, 2006a

The plant would require approximately 3,000 to 3,500 gallons per minute (4.32 to 5.04 million gallons per day or 4,850 to 5,600 acre-feet per year) of "make-up water". The majority of make-up water would be used for cooling tower make-up due to the large evaporation, drift, and blowdown losses. A raw water tank would provide an on-site storage for service water and cooling tower make-up usage. A coal burning power plant is a thermoelectric plant, and works by heating water in a boiler until it turns into steam. After the steam is used to spin the turbine-generator that produces electricity, it is sent to the condenser to be cooled back into water. Most of the water used in thermoelectric power generation is used in the condenser to cool the steam back into water. Then the condensed water is pumped back to the steam generator to become steam again while the cooling water is either discharged as return flow or is recycled through cooling ponds or towers.

Up to 811 gal/minute of wastewater would be discharged and would consist of concentrated river water and trace amounts of cooling tower water and boiler water treatment chemicals (DEQ, 2005a). SME plans to discharge this wastewater into the City of Great Falls wastewater treatment plant, thereby avoiding direct discharge of effluent into the Missouri River.

A hydrated ash reinjection or dry FGD system and pulse jet baghouse (fabric filter) would be installed "downstream" of the boiler to further reduce sulfur dioxide levels and remove fly ash in the flue gas stream. The baghouse collects the fly ash for disposal. Flue gas enters the baghouse through an inlet plenum, and the particulate matter is collected on the outside surface of the bags. Pulsating air is used to remove the ash from the filter media and discharge the ash to the baghouse hoppers. The fly ash would be removed from the baghouse and transported to a filter separator and then to a storage silo. Bed ash is removed from the fluidized bed and cooled in bed ash coolers. Cooled bed ash would be discharged into a storage silo, which is sized for 3-day storage. From the silos, the fly ash and bed ash are mixed with wastewater to control dust and then trucked to a dedicated ash landfill, where the wet ash will solidify (SME, 2004b). The solid waste byproduct of the combustion process at the HGS would be approximately 225 tons of fly and bed ash that would require disposal in an environmentally acceptable manner on a daily basis (SME, 2005h).

After consulting with DEQ on solid waste management and examining two disposal options, SME plans to dispose of coal combustion byproduct within the confines of the rail loop adjacent to the generating facility. The area within the rail loop would be laid out in a rectangular grid consisting of approximately 100 acres (40 ha) or 12 three-acre parcels. The grid would be three parcels wide and four parcels long. The twelve 1,700 by 2,300-foot (520 by 700 m) cells could be opened one at a time on "as needed" basis with an estimated byproduct storage capacity of approximately three years. The monofill facility would have a storage capacity for solid waste byproducts commensurate with the estimated life of the HGS – in excess of 35 years.

The rail loop and waste material landfill cells would be located on land that is relatively flat, as is typical for fuel unloading and related rail activities. Each cell would be excavated to a depth of 36 feet (11 m) and have an estimated combustion byproduct storage capacity of 36 months. The monofill cells would be designed as self-contained units with recompacted clay liners. As each cell was filled, a layer of compacted clay would be placed over the waste material. The final stage in the process, at an above-grade height of 22 feet (7 m), would be an evapo-transpiration cover and vegetation-sustaining layer of topsoil held in reserve from the process of opening an adjacent storage cell. All storage and reclamation materials necessary for this process can be found onsite.

In addition to the fly and bed ash there will be approximately 2.0 tons per day of equivalent solid waste byproduct produced by the raw water treatment facility. This slurry would consist of concentrated sediment naturally occurring in raw water taken from the Missouri River for use at HGS. The sediment concentrate resulting from the raw water treatment process would be further processed by coagulating the material in a thickener process to reduce residual moisture. At this point the sediment concentrate would have a consistency well-suited for injection into the fly ash and bed ash pug mills.

The solid waste byproduct of the raw water treatment process will be deposited in the onsite monofill disposal site where the fly and bed ash will be contained. The mixing of materials (bed or fly ash with the concentrated sediment in the pug mills below each ash storage silo) would result in a mixture which would set up like a light weight concrete material. The concentrated sediments would be encapsulated through this process. This material will be evenly spread throughout the monofill cells. The use of concentrated sediment would result in lower quantities of water needed for dust suppression within the pug mill and in the silo unloading processes.

Electricity from the operation of the proposed HGS would furnish the base load component of SME's proposed integrated power supply portfolio. However, under the Proposed Action, SME and its member cooperatives would continue to purchase power from WAPA as well as continue to invest in energy conservation and efficiency, as mandated since 1997 by the State of Montana in Senate Bill 390. In addition, SME proposes to purchase and/or generate an Environmentally Preferred Product, probably wind energy. As discussed below, SME's Board has expressed its intention to construct four 1.5-MW wind turbines on the Salem site on a gentle ridge within the property that would be acquired for the HGS. In addition to generating a small amount of intermittent power, these proposed turbines would enable SME engineers to gain on-the-ground experience integrating wind as part of the power supply portfolio.

2.2.2.3 Wind Turbines

One additional element of the Proposed Action that would take place at the Salem site is the construction and operation of a wind generation project having an aggregate capacity of approximately 6 MW distributed between a maximum of four individual wind turbine generator (WTG) sites. Although SME intends to seek different funding for the construction of these structures (that is, they are not part of the RD loan application), they are included as a part of the Proposed Action. Wind energy was discussed at some length in Section 2.1.3.1 in the context of why it alone could not supply the entire purpose and need for the project, and that discussion will not be repeated here. A brief description of the proposed facilities will suffice.


Figure 2-28. 1.5-MW GE Wind Turbines at Judith Gap, Montana

Wind towers would be tubular multi-sectional, having a base diameter of approximately 18 feet (5.5 m) and be erected onsite. Towers are anticipated to have a height of 262 feet (80 m) at the rotor. The wind turbine is expected to have three blades, with an overall diameter of 250-270 feet (77-82.5 m) or radius of 125-135 feet (38-41 m). Thus, when a rotating blade is in the upright position, its tip would rise approximately 387-397 feet (118-121 m) above the

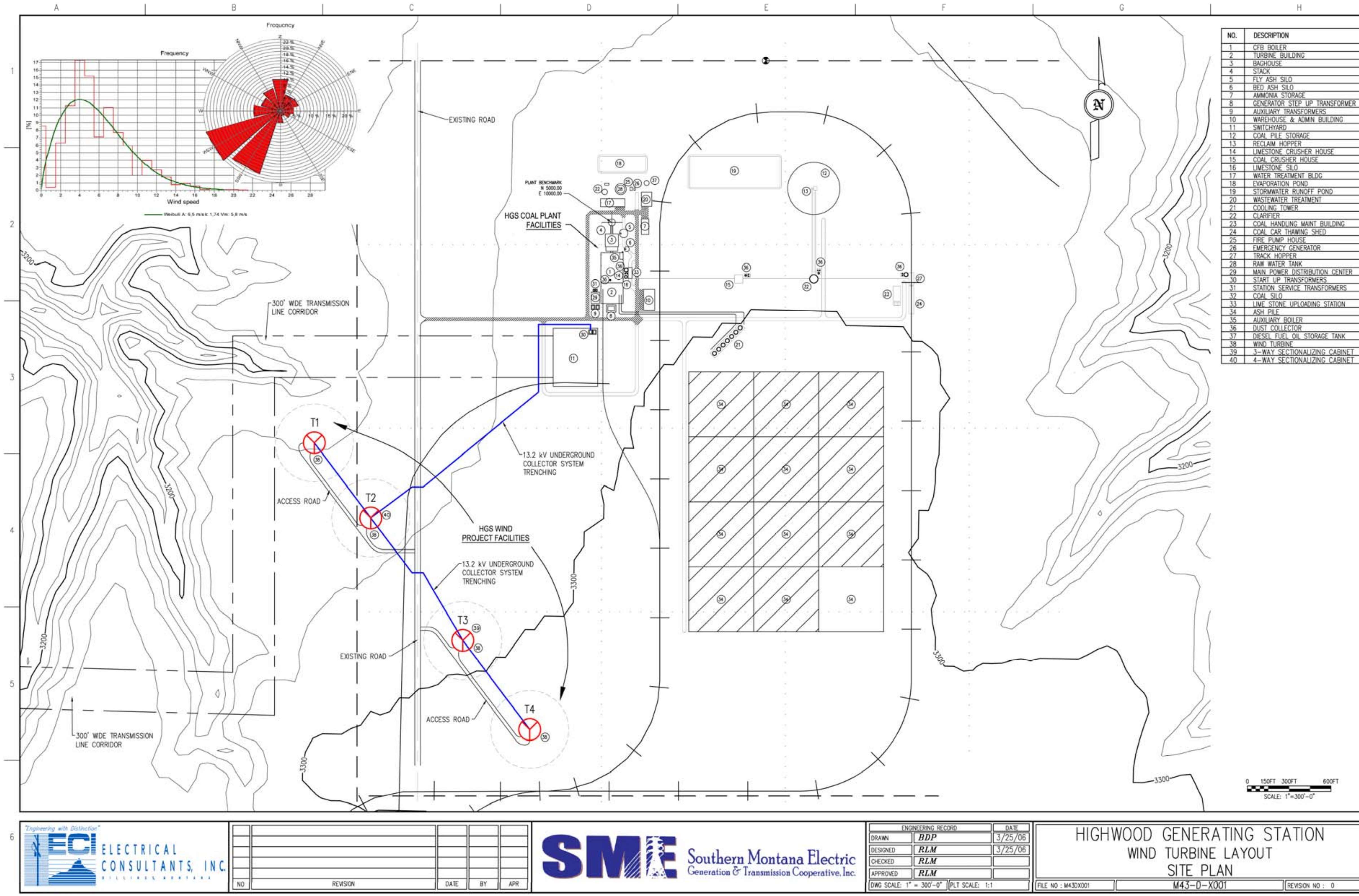


Figure 2-29. Preliminary HGS Wind Turbine Site Plan

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ground surface. The tower and turbines would be erected on a spread footing foundation approximately 48 feet (15 m) across and up to four feet (1.2 m) thick; a volume of 240 cubic yards (183 cubic meters) of concrete with 40,000 lbs. (18,000 kg) of reinforcing steel is needed for each foundation (EC., 2006). The overall appearance of the wind machines would be very similar to that shown in Figure 2-28 at Judith Gap, MT.

Development of the HGS Wind Project would require approximately 100 acres (40 ha) to be occupied by up to four wind machines. The location of these machines would be generally southwest of the HGS Coal-Fired Plant site (Figure 2-29). Elevation above sea level for the wind turbine tower foundations would be approximately 3,540 feet (1,079 m). This location is near the highest point in the surrounding area, roughly equivalent to a promontory located approximately ½ mile to the southwest that has long been a radio tower communication site. Wind towers would be upwind from the HGS coal-fired plant facilities, oriented to form a single string of turbines in order to capture energy from the prevailing westerly and southwest winds. Spacing between wind turbines would be approximately 800 feet (240 m). Final siting for the WTGs must be coordinated with placement of the 230-kV transmission lines, rail spur and HGS main access road (EC, 2006).

Excavation and grading would be required at each WTG location for foundation placement, as well as a temporary crane pad for tower erection. The total area of site disturbance for each tower is estimated at approximately 1.1 acres (0.4 ha). A portion of the excavated native soil materials would be used to establish natural drainage away from the turbine tower foundation. Additional soils disturbance would occur for installation of high voltage underground cable (collection system), communications cable and the electrical grounding system between the HGS Switchyard and WTG locations. A total of approximately 3,300 feet (1,000 m) of excavated trench, typically three feet (0.9 m) wide by four feet (1.2 m) deep, would be required.

Ongoing operation and maintenance would require construction of approximately 2,200 lineal feet (670 m) of access roads. Road construction impacts would be reasonably small considering the relatively minor change in elevation between WTG locations, the HGS plant site and existing county road. Access road construction would be limited to placement of pit run and final road base gradation materials to establish a 25-foot (8 m) wide drivable surface with elevations of 12 inches (0.3 m) or more above natural grade, or as otherwise required to interface with an improved primary plant access road. Culverts to re-establish natural drainage would be utilized where required; in addition, riprap and flow diversion devices would be specified as required for erosion protection. Top soils removed at the start of construction would be spread adjacent to completed roadways and disturbed areas would be reseeded with natural vegetation (EC, 2006).

Integration of wind generation into a wholesale power supply portfolio requires a proper balance between the operating characteristics of base load generation, power purchase agreement flexibility and cost of service objectives. Purchasing or generating wind power has an associated expense that must be addressed as the wholesale power supplier meets its obligation to supply a reliable, affordable and balanced supply of wholesale electric energy and related services to its member systems. The integration of wind into a power supply portfolio can be challenging and the "all in" costs related to this resource must be objectively considered in order to accurately reflect the contribution this resource will make to supply portfolio pricing (SME, 2005c).

When compared to other generation technologies, wind power has a number of unique operating characteristics that must be included in an objective estimate of the cost of wind generation. Wind generation is uncertain, variable and cannot be dispatched. Wind power facilities generate electricity only when the wind is blowing, with production facility output very dependent on wind speed. Unfortunately, wind speed cannot be predicted with any degree of accuracy over a predetermined period of time. Therefore, to "firm" wind power for sale into the market, or to base load dispatch wind power directly into the system grid in a predetermined load control area, requires a dedicated source of operating and spinning reserve capacity equal to the production ability of the wind resource. Absent a commensurate level of reserve capacity, wind power does not meet the fundamental requirements of a dispatchable source of generation, and simply ignoring the associated cost of "firming" renders any economic comparison of wind power to traditional base load generation fundamentally flawed.

The uncertainty and variability of wind power also presents operational issues for the system dispatch operator. The system dispatch operator has the responsibility to determine how much generation must be "on line" to meet the forecasted system load requirement on an hourly basis. This scheduling activity typically begins a full day in advance, with anticipated system load and generation capacity being "balanced" on an hourly basis.

In a system comprised of both wind and conventional base load generation, the dispatch operator will determine on an "hour ahead basis" if there is sufficient generation capacity on line to meet the system load requirements – with and without the use of wind generation. If additional generation resources are needed, the system dispatch operator is responsible for acquiring generation capacity necessary to meet system load requirements. Typically, the system dispatcher would attempt to meet these requirements with purchases from available lowest-cost generation resources located within the load control area that the dispatch operator is responsible for keeping in "balance." The process of seeking, purchasing and dispatching supplemental generation on the basis of cost is referred to as "economic dispatch."

Once wind and other generation resources are brought on line, the system dispatch operator would have the responsibility to maintain the

"FIRMING" AND "LOAD CONTROL AREA"

The term **<u>"firming"</u>** in this instance describes the process of having a base load generation resource in "spinning reserve" – ready to cover load with no more than a one-hour notice. Firming is necessary in the case of wind generation because the amount of energy produced at these facilities can (and does) vary as a function of the availability of wind. If wind generation has been earmarked to cover a particular load, the entity relying on that resource to cover load must have an alternate source of generation to cover the load when the wind does not blow.

<u>"Load control area"</u> is a defined portion of the electrical grid where an entity (generally the predominate owner of the transmission facilities in that area) is responsible for ensuring that for every hour of the year (8,760 hours) they will balance the demand for electricity with supply of electric energy. The task is accomplished by ensuring that the electric energy that is being produced/purchased by load serving entities (such as SME) with load in that particular geographic area, have adequate generation on line or have scheduled energy for delivery into that area adequate to cover the load they serve. In the event there is discrepancy between load and supply, the load control area services provider will go to the open market and purchase the energy requirement shortfall and bill the entity that was short on supply for all costs associated with that transaction. If a load serving entity has more energy delivered than they have load, the load control area services provider will sell the surplus and return the proceeds to the supplier that over delivered the revenue from that transaction – less FERC-approved charges. The concept of load/supply reconciliation is referred to as balancing the system when in energy imbalance.

"match" between system load requirements and generation supply. If the system is in balance – implying that generation resources have a constant output that matches load control area requirements – the electric system is said to be in "steady state." However, should the wind suddenly or unexpectedly decrease or stop, the contribution wind capacity was making to the system's generation requirements would decrease accordingly and the system operator would have to readjust the mix of generation resources and compensate for this loss of generation capacity.

The need for additional generation may be met with capacity owned by the load control area provider/operator or by making purchases of generation capacity from resources willing to sell capacity at the prevailing market rate. It should be noted that the purchase of generation capacity on short notice could be very costly. There is a significant cost associated with starting additional generators and bringing them on line with short notice to cover the imbalance between system load requirements and on-line generation capacity.

Recently, there has been considerable discussion on the relative cost of wind generation. Based on an analysis of current Mid-Columbia energy market prices, it appears as though the price being quoted for the cost of wind generation may not represent the "all in" cost of this resource. The following calculation (Table 2-12) represents the underlying economics associated with determining the "all in" cost of wind generation on a specific date – including "firming."

Table 2-12. Wind Power Firming Cost

Assume:			
Generation Form	Cost		Comments:
Wind Power	$35	/mWhr	After production tax credits
Purchased Power	$84	/mWhr	Average Cost for Firm On and Off Peak Power at the Mid Columbia Electricity Index on October 15, 2005.
Assume the wind power is available 36% of the time which is a one-hour increment, and for each hour the balance of the power will be supplied by the Purchased Power Component.			
Wind Power Component	$12.60		
Purchase Power Component	$53.64		
Total Power Cost	**$66.24**	/mWhr	

Table 2-12 demonstrates that while the $35/MWh (after production tax credit) cost of wind power is highly competitive with fossil fuel energy sources, the "penalty" of its intermittency is a higher overall price ($66.24/MWh) due to having to purchase costly spinning reserve and power to fill in when the wind is not blowing.

Cost-effective generation resource management is a multidimensional task complicated by load variation, generation availability and cost of production. System load requirements can vary greatly by time of the day, day of the week and season. This load requirement dynamic does not match particularly well with the lack of predictability inherent in wind generation capacity. Central station electric power cannot be stored in quantities sufficient in size to cover an appreciable level of fluctuation in system load requirements. Essentially, the electric grid operates as a large synchronous machine whereby electricity must be produced and consumed on an instantaneous basis.

The HGS would be the only dispatchable source of generation in the entire SME system. The HGS unit would have, relatively speaking, limited load following ability. When operating at or above its minimum load level, the HGS is expected to be able to increase load or “ramp up” at approximately 3 MW to 10 MW per minute. For comparison purposes, a similar sized gas-fired combined cycle plant would be able to ramp up at approximately 10 MW to 15 MW per minute to cover system imbalances – but at a much higher cost.

During the time that the unit is ramping up or down to meet a variance in load, the unit’s performance (i.e., heat rate) suffers and its emissions rates increase. Variations in a generating unit’s operating characteristics are due to the “flywheel” effect of the generating unit as it responds to demands from its operator to alter energy production. As the generating unit’s “moment of inertia” must be overcome relative to variations in energy production, unit operating efficiencies decline. When a particular generating unit is called upon to increase energy production output, operating efficiency may decline to the point that additional sources of generation are needed until the primary generating unit is able to respond to contemporary load requirements. The limitations of the flywheel effect and overcoming a moment of inertia are also true of wind power. The period of time when generating units are the most efficient is when they are operating at “steady state” – which means the generating unit no longer needs to overcome the flywheel effect and the system load requirements and generation resources are in balance for a specific load control area.

Likewise, should the wind suddenly or unexpectedly pick up, the wind power production facilities would “cut-in” and begin producing electricity. Under this scenario, the system dispatch operator would reduce the output from the HGS (or some other dispatchable source of base load capacity) in order to allow for the additional energy from the wind power facilities. This rapid curtailment in base load capacity may also create problems in the form of performance degradation and higher emissions rates. Once again, this mild form of system instability is due to the inherent design characteristics of dispatchable base load generation. Throughout the period of base load generation “ramp down,” more energy is used at any load point than would be used at that same point under steady state operation. This phenomenon results in increased emissions and performance penalties as compared to the steady state condition where optimum efficiency and lowest emissions are possible.

Typically, natural gas-fired combined cycle facilities are looked to as a source of generation reserves well suited to satisfy system production/load imbalances in a specific load control area. However, recent increases in the price of natural gas have rendered a wind/combined cycle plant combination a very expensive source of base load generation. In fact, when viewed in the context of the added pressure natural gas-fired generation has had on the supply and price of natural gas, an unintended consequence of this arrangement has been an inadvertent increase in the cost of natural gas. With natural gas serving as a primary source for home heating in much of SME’s service territory, fixed income and low income consumers are negatively impacted with increased cost for home heating and a higher cost for electricity that would more cost-effectively be met through SME’s contemplated supply portfolio.

The challenge of maintaining "steady state" is significantly affected by the introduction of generation resources dispatchable only on a non-firm basis. A base-load, fully dispatchable source of generation will always be needed to serve as the "regulating" energy production facility governing the match between production and system load requirements. The base-load generating unit providing system regulation will utilize its governor control system to determine generation requirements necessary to match load control area energy requirements with generation capacity. This fundamental system operating requirement cannot be satisfied by a wind power source of generation that is not fully dispatchable on a predetermined basis.

There are two distinct load fluctuation patterns realized from the utilization of wind power. The first is the instantaneous fluctuation of power caused by the variability in wind power. These swings occur over fractions of a second. The second fluctuation occurs over a longer period of time, which can be fractions of a minute to fractions of an hour. Added to these fluctuations are the changing system load requirements. In order to limit the impacts of fuel costs, increased emissions and additional system imbalance costs, SME believes that it is in the best interests of its member/owners to limit the percentage of its power generation portfolio from wind generation to a relatively low amount, in a range of 2-3 percent of the system load. This is generally considered to be in the range of the control system response of the boiler, turbine, and generator controls for a coal-fired unit. Under this scenario, the uncertain and/or unplanned startup and shutdown of wind generation will have little effect on the overall performance of the proposed power plant. It may be that, in time, reliance on wind or other sources of renewable generation could be increased, but at this time wind is still not a proven economically dispatchable source of base load generation.

The Montana Legislature has set a goal of 15 percent for the renewable resource portion for power supply portfolios. The requirement to meet this objective will ramp in over time with the ultimate goal of 15 percent beginning in the year 2015. Although not specifically required to do so by the recent action of the Montana Legislature, SME is focused on integrating wind power into its supply portfolio. To ensure the highest level of operating flexibility of the contemplated HGS, SME is installing a modest amount of wind generation (6 MW) to test the value of this resource. SME will also consider power purchase agreements with qualified wind power producers operating in larger load control areas as an additional source of renewable energy. A wind resource-based power purchase agreement would enable SME to structure the integration of wind resources into the supply mix as a "firm" resource – complete with operating and spinning reserves.

SME may eventually decide to expand on its test program to the extent where it would own, operate and maintain additional wind generation. However, to properly place this activity in perspective would require a detailed analysis of the total cost of this resource as experienced by the test program is implemented. This analysis would require extensive, all-inclusive economic modeling of the costs associated with project development, construction, reserves (both operating and spinning), economic dispatch, transmission capacity and other costs associated with the contemplated test facility.

2.2.2.4 Connected Actions

Projects of this scale and scope always entail "connected actions", that is, other actions, projects, or processes that are linked in some way to or are dependent on the Proposed Action. Connected actions are influenced by the Proposed Action; either they would not occur without the Proposed Action or their magnitude, nature, location or timing are affected by the Proposed Action.

The coal and limestone to be combusted in the CFB boiler at the proposed HGS would be purchased and transported from other existing companies conducting ongoing operations at existing mines and quarries and are therefore not part of the Proposed Action per se. Neither SME nor the suppliers in question would be opening new extractive facilities to supply the raw materials used in the proposed HGS. However, by using raw materials from the facilities in question, SME may contribute to expanded operations and would be contributing incrementally to the impacts associated with mining and quarrying coal and limestone, respectively. In the case of coal, which would be used in much larger quantities than limestone (45 times as much, by weight) these impacts have already been addressed and mitigated in Environmental Impact Statements for the Spring Creek and Decker coal mines (USGS-MDSL, 1977; USGS-MDSL, 1979; MDSL, 1980). These EISs are hereby incorporated by reference into the present EIS.

In 2004, the Spring Creek Mine, operated by the Spring Creek Coal Company in southeastern Montana's Powder River Basin, was the 13th largest coal mine in the United States, producing approximately 12.1 million tons of coal. The Decker Mine nearby, operated by the Decker Coal Company, was the 18th largest coal mine in the U.S. (by tonnage produced), with 2004 production of 8.2 million tons. They were the second and third largest coal mines in Montana, respectively (EIA, 2004b). Projected coal consumption of 1,314,000 tons per year for the proposed HGS would therefore represent about 9 percent of the Spring Creek Mine's annual production or about 14 percent of Decker's.

Figure 2-30. Graymont's Indian Creek Lime Plant near Townsend, MT

SME would purchase approximately 3,888 tons per year of limestone from Graymont's Indian Creek lime plant to be injected in the CFB boiler and used as bed material. The Indian Creek plant is located near Townsend, MT, just north of the Limestone Hills. It produces lime in two coal/coke fired preheater kilns and is equipped with lime sizing and storage facilities as well as a hydrator capable of producing 300 tons of hydrated lime per day (Graymont, 2005). Operation of this facility is regulated by DEQ Operating Permit #00105 and is not addressed here.

The plant's limestone quarry is on the south side of Indian Creek. High quality limestone from the quarry is trucked to a crushing plant where it is sized and conveyed to a large storage pile next to the preheater kilns. Bulk truck loading facilities are provided at the plant site (Graymont, 2005); HGS limestone deliveries from the Indian Creek plant would be made by truck.

In the case of other actions described above, including constructing and operating transmission line interconnections, the railroad spur, and water and wastewater pipelines, as well as transporting coal to the HGS in unit trains along the rail spur, while these do not constitute constructing and operating the power plant per se, they are indeed integral to the Proposed Action itself. Thus, they are not considered connected actions in this project, but rather sub-actions of the overall Proposed Action. However, environmental impacts from the transport of coal are not part of the Proposed Action and thus not evaluated here.

2.2.3 Alternative Site – Industrial Park Site

The Industrial Park site is located in the Southern half of Section 30, Township 21 North, Range 4 East. It is just east of Highway 87, about ¾ mile (1.2 km) north of the Missouri River and ½ mile (0.8 km) east of a mobile home park (see Figure 2-23). The City of Great Falls has designated this site as the Central Montana Agricultural and Technology Park, that is, as an industrial park. Construction and operation of the 250-MW, CFB coal-fired power plant at the Industrial Park site would be the same as described in section 2.2.2 for the Salem site, except for the differences described below. Figure 2-31 displays the rough layout of the Industrial Park site and Figures 2-32 and 2-33 depict scenes from the site.

Five miles (8 km) of new track and railroad bed would be needed, slightly less than the distance for the Salem site. The rail spur would start north of the Missouri River and travel west to the plant site. A 17-mile (27-km) long pipeline (compared to less than two miles for the Salem site) would be needed to transport make-up water from an intake structure upstream of the Morony Dam on the Missouri River to the plant. Precise locations of transmission line corridors have not yet been determined, though it is likely that one transmission line would go to the Great Falls Switchyard, about a mile east of the Industrial Park site. The specific rights-of-way for potable water and wastewater lines have also not yet been selected, though they would likely be shorter than for the Salem site.

Construction at the Industrial Park site would take the same length of time as at the Salem site, approximately three and a half years, and the workforce would be about the same size – averaging between 300 and 400 workers at any one time with an estimated peak construction workforce approaching 550 (Chaffee, 2005).

The proposed 250-MW (net) generating station would include the same equipment and component parts, would be operated identically and would consume the same quantities of raw materials as in the Proposed Action.

Disposal of fly and bed ash would not take place onsite at the Industrial Park site, because of the smaller area. Instead, ash would be shipped away for disposal in an approved landfill, for reuse as an industrial byproduct, or both.

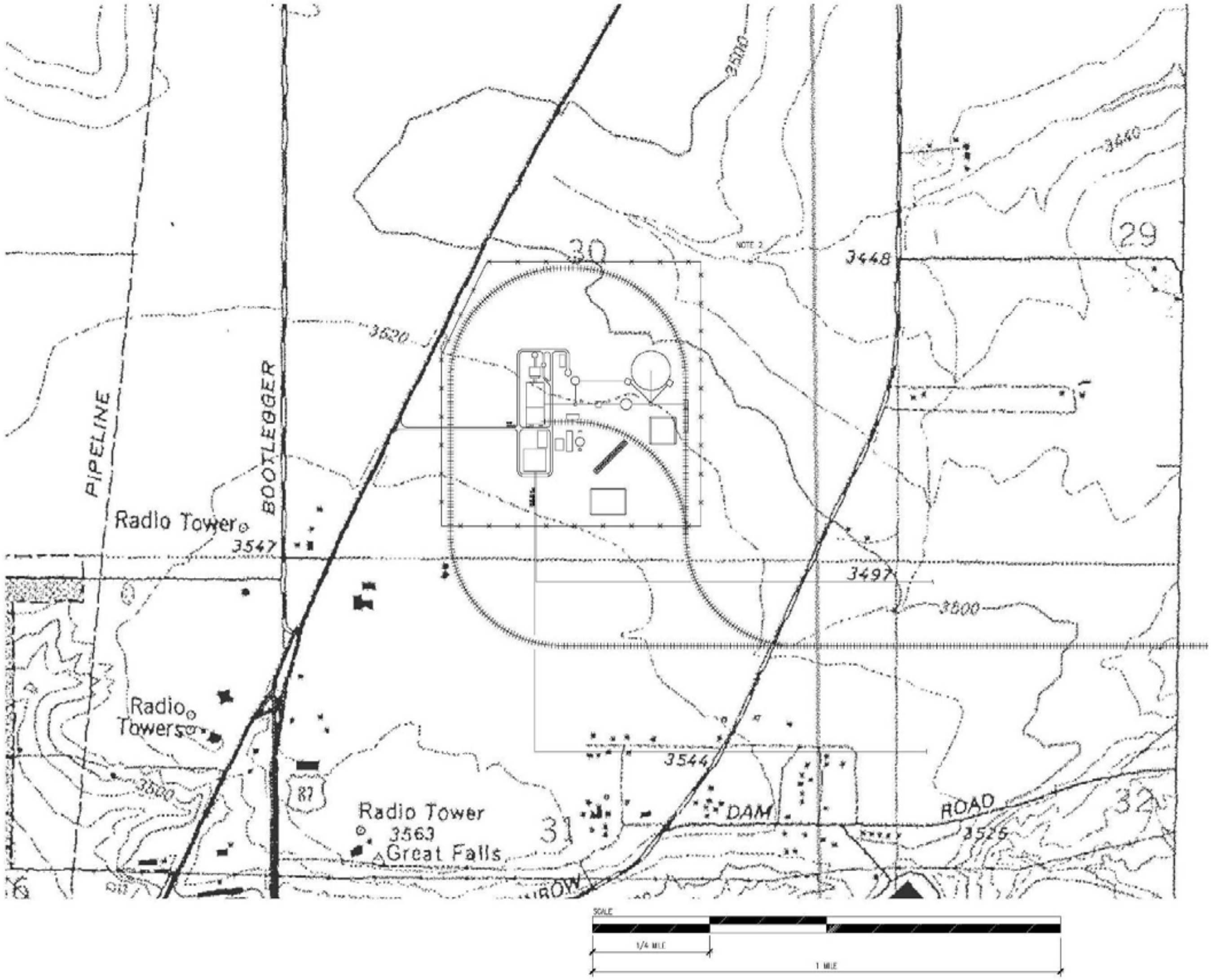

Figure 2-31. Preliminary Layout of the Industrial Park Site (Central Montana Agricultural and Technology Park)

Figure 2-32. View of the Industrial Park Site

Figure 2-33. View from the Industrial Park Site West Toward Suburban Subdivision North of Great Falls

SME has not committed to building and operating wind turbines at the Industrial Park site. However, it would continue to purchase power from WAPA, purchase 1 MW of EPP, and invest a minimum of 2.4 percent of annual retail sales in energy efficiency and conservation per Montana Senate Bill 390.

The connected actions of mining coal and quarrying limestone would be the same as in the Proposed Action.

2.2.4 COMPARISON OF ALTERNATIVES

Table 2-13 on the next page is a matrix comparing the potential impacts by resource topic of each of the alternatives analyzed fully in this EIS.

Table 2-13. Comparison of Direct, Indirect, and Cumulative Environmental Impacts of Alternatives

Affected Resource or Issue	Alternative 1: No Action	Alternative 2: Highwood Generating Station – Salem Site (Proposed Action)	Alternative 3: Industrial Park Site (Generating Station at Alternate Site)
Soils, Topography, and Geology	▪ No impacts on the topography or the geology of the Salem or Industrial sites. ▪ Negligible to minor, long-term adverse impacts on soils would continue from existing land use practices.	▪ Negligible to minor impacts on topography and geology. ▪ Soils impacts from construction activities would have a moderate magnitude, medium-term duration, medium extent, and probable likelihood. ▪ Overall rating from construction impacts adverse and non-significant. ▪ Impacts from operation of the waste monofill would be adverse but non-significant, and of minor magnitude, long-term duration, small extent, and probable likelihood. ▪ Overall impacts on soil at the Salem site would be adverse; while impacts would most likely be non-significant, there is potential for them to become significant.	▪ Negligible to minor impacts on topography and geology. ▪ Soils impacts from construction activities would have a minor magnitude, medium-term duration, medium extent, and probable likelihood. ▪ Overall rating from construction impacts adverse and non-significant. ▪ Operation-related impacts on soil resources would be adverse but non-significant, and of minor magnitude, short-term duration, small extent, and possible likelihood. ▪ Overall impact on soil at the alternative site would be adverse and non-significant. Impacts at an alternative ash disposal site are unknown and site-dependent.
Water Resources	▪ Would not significantly, adversely affect water resources at or near the Salem Site or the Industrial Park. ▪ Negligible to minor, long-term adverse impacts on water resources would continue from existing agricultural land uses. ▪ Could potentially contribute	▪ Construction of the HGS would likely entail increased storm water runoff carrying sediment and contamination loads into surface water, and the potential for contamination from construction equipment and activities infiltrating area soils and percolating down into	▪ Construction of the HGS would likely entail increased storm water runoff carrying sediment and contamination loads into surface water, and the potential for contamination from construction equipment and activities infiltrating area soils and percolating down into

Water Resources (continued)	indirectly and cumulatively to water resource impacts at the sites of other generation sources from which power is purchased.	the groundwater. Impacts to water quality would be mitigated (reduced but not entirely eliminated) through BMPs. ▪ Negligible to minor impact on wetlands and floodplains. ▪ Water withdrawals from the Missouri River for HGS operation would reduce flows by 0.31% in a worst-case scenario. ▪ Effluent would be discharged to City of Great Falls sewage treatment system rather than directly into the Missouri River after on-site treatment. ▪ Impacts from power plant operation would be of moderate magnitude, long term duration, medium extent, and probable likelihood. ▪ Overall rating for impacts on water resources from the operation phase of the power plant would be adverse and most likely non-significant, but with the potential to become significant.	the groundwater. Impacts to water quality would be mitigated (reduced but not entirely eliminated) through BMPs. ▪ Negligible to minor impact on wetlands and floodplains. ▪ Water withdrawals from the Missouri River for HGS operation would reduce flows by 0.31% in a worst-case scenario. ▪ Effluent would be discharged to City of Great Falls sewage treatment system rather than directly into the Missouri River after on-site treatment. ▪ Impacts from power plant operation would be of moderate magnitude, long term duration, medium extent, and probable likelihood. ▪ Overall rating for impacts on water resources from the operation phase of the power plant would be adverse and most likely non-significant, but with the potential to become significant.
Air Quality	▪ Would not result in any direct air quality impacts on either the Salem or Industrial Park sites. ▪ Would contribute indirectly and cumulatively to air quality impacts at those power plants from which SME would purchase electricity, although these impacts cannot be specified.	▪ Short-term, minor to moderate degradation of local air quality from construction activities. ▪ Long-term minor to moderate degradation of local air quality from HGS operations. ▪ Long-term minor impacts on sensitive species from criteria pollutant emissions and/or trace	▪ Short-term, minor to moderate degradation of local air quality from construction activities. ▪ Long-term minor to moderate degradation of local air quality from HGS operations. ▪ Long-term minor impacts on sensitive species from criteria pollutant emissions and/or trace

Air Quality (continued)		element deposition. ▪ Off-site impacts on PSD Class I increments and AQRVs (regional haze and acid deposition) ranging from negligible to moderate in intensity. ▪ Annual mercury emissions from the HGS would be approximately 34.5 lbs. (15.7 kg), constituting a minor incremental contribution to cumulative state, national, and global mercury emissions. State and national mercury emissions are declining due to new rules and controls; global emissions are still rising. HGS's Hg emissions are unlikely to measurably increase rates of mercury deposition, methylmercury uptake and bioaccumulation, or present unacceptable health risks to humans or wildlife locally or in the state. ▪ Minor, incremental contribution to the accumulation of greenhouse gases in the atmosphere, which most scientists believe is forcing climate change. ▪ Overall air quality impacts would be adverse and most likely non-significant, but with the potential to become significant.	element deposition. ▪ Off-site impacts on PSD Class I increments and AQRVs (regional haze and acid deposition) ranging from negligible to moderate in intensity. ▪ Annual mercury emissions from the HGS would be approximately 34.5 lbs. (15.7 kg), constituting a minor incremental contribution to cumulative state, national, and global mercury emissions. State and national mercury emissions are declining due to new rules and controls; global emissions are still rising. HGS's Hg emissions are unlikely to measurably increase rates of mercury deposition, methylmercury uptake and bioaccumulation, or present unacceptable health risks to humans or wildlife locally or in the state. ▪ Minor, incremental contribution to the accumulation of greenhouse gases in the atmosphere, which most scientists believe is forcing climate change. ▪ Overall air quality impacts would be adverse and most likely non-significant, but with the potential to become significant.
Biological Resources	▪ No direct impacts on biological resources at either the Salem or Industrial Park sites.	▪ Temporarily displace terrestrial wildlife due to removal of vegetation and disturbance from	▪ Temporarily displace terrestrial wildlife due to removal of vegetation and disturbance from

Biological Resources (continued)	▪ Could contribute indirectly and cumulatively to impacts on flora and fauna from those power plants from which SME would purchase electricity, although these impacts cannot be specified.	construction equipment. ▪ Eliminate potential habitats, but unlikely to adversely affect, state-listed species of concern from permanent removal of vegetation. ▪ Short-term harm to wildlife & vegetation by degrading air quality. ▪ Short-term harm to aquatic biota from degraded water quality. ▪ Long-term increase in mortality of terrestrial mammals by rail strikes and increased traffic on access road. ▪ Increase mortality to birds and bats from blade strikes on wind turbines. ▪ Temporarily disturb habitats along water pipeline routes during construction activities. ▪ Temporarily or permanently disturb wetland habitats for installation of water intake. ▪ In sum, impacts on biological resources would be of minor magnitude, long-term duration, small extent and probable likelihood. ▪ Overall biological resources impact would be adverse and non-significant, but with the potential to become significant.	construction equipment. ▪ Eliminate potential habitats, but unlikely to adversely affect, state-listed species of concern from permanent removal of vegetation. ▪ Short-term harm to wildlife & vegetation by degrading air quality. ▪ Temporarily disturb habitat along water pipeline routes during construction activities. ▪ Temporarily or permanently disturb wetland habitats for installation of water intake. ▪ In sum, impacts on biological resources would be of minor magnitude, long-term duration, small extent and probable likelihood. ▪ Overall biological resources impact would be adverse and non-significant, but with the potential to become significant.
Acoustic Environment	▪ No direct noise impacts on either the Salem or Industrial Park sites. ▪ Would contribute indirectly to noise impacts at other plants from which SME would purchase electricity.	▪ Noise levels from the operation of the HGS, including intermittent noise sources, would be audible for several miles from the site. ▪ Predicted noise levels from HGS	▪ Noise levels from the operation of the HGS, including intermittent noise sources, would be audible for several miles from the site. ▪ Predicted noise levels are equal to

Acoustic Environment (continued)		and wind turbines are equal to or less than the EPA guideline at receptors near the Salem site. ▪ Noise levels are predicted to be approximately equal to the existing ambient noise levels during quiet periods at approximately 3.1 miles (5 km) from the Salem site. ▪ At all receptor locations, the power plant and wind turbine noise levels are predicted to be less than the 50 dBA nighttime noise limit of the Great Falls Municipal Code for residences, and less than or equal to the EPA Ldn 55 dBA guideline. ▪ Overall noise impacts would be minor, localized and long-term; while impacts would most likely be non-significant, there is some potential for the impacts to become significant.	or less than the EPA guideline at the receptor locations around the Industrial Park site. ▪ Noise levels are predicted to be approximately equal to the existing ambient noise levels during quiet periods at approx. 1.2 miles (1.9 km) from the Industrial Park site. ▪ At all receptor locations, the power plant noise levels are predicted to be less than the 50 dBA nighttime noise limit of the Great Falls Municipal Code for residences, and less than or equal to the EPA Ldn 55 dBA guideline. ▪ Overall noise impacts would be minor, localized, and long-term; while impacts would most likely be non-significant, there is some potential for the impacts to become significant.
Recreation	▪ No direct impacts on recreation facilities or opportunities in the area. ▪ Would contribute indirectly to recreation impacts associated with those generating stations from which SME would purchase electricity.	▪ Construction and operation of the HGS would entail negligible to at most minor impacts on recreation in the immediate project vicinity and wider Great Falls area. ▪ The Lewis and Clark staging area historic site would be impacted by the Proposed Action. ▪ Generally, impacts on recreation would be of minor magnitude, long-term duration, small extent, and probable likelihood. ▪ Overall impacts on recreation would	▪ Construction and operation of the SME power plant at the alternate Industrial Park site would entail negligible to at most minor impacts on recreation in the immediate project vicinity and wider Great Falls area. ▪ Upper portions of the proposed generating station would be visible to park users and recreationists along the Missouri River in Great Falls. ▪ Overall impacts on recreation would

Recreation (continued)		be adverse and most likely non-significant, but with some potential to become significant.	be adverse and most likely non-significant, but with some potential to become significant.
Cultural Resources	▪ No direct impacts on cultural resources in the area. ▪ Could potentially contribute indirectly to cultural resources impacts associated with those generating stations from which SME would purchase electricity.	▪ Adversely affect Great Falls Portage NHL from site preparation, staging, construction, maintenance, operations, and connected actions associate with power plant, water lines, transmission lines, rail supply lines. ▪ Other cultural properties within the APE would not be affected by the proposed undertaking. ▪ It appears that no TCPs would be affected. ▪ In sum, cultural resources impact would be of major magnitude, long-term duration, medium or localized extent, and probable likelihood. ▪ Overall impact would be adverse and significant; significance of impacts can be reduced but not eliminated by mitigation.	▪ Would likely have no effect on cultural resources due to their apparent absence from the Industrial Park site. ▪ It appears that no TCPs would be affected. ▪ Constructing transmission lines, water supply and wastewater lines could potentially affect undiscovered cultural resources. ▪ Overall impact likely to be negligible to minor.
Visual Resources	▪ No direct impacts on visual resources in the area. ▪ Could potentially contribute indirectly and incrementally to visual resources impacts associated with those power sources from which SME would purchase electricity.	▪ The HGS and wind turbines would have scenic impacts of major magnitude, long-term duration, small extent, and high probability. ▪ While the HGS and wind turbines would clearly diminish scenic values within the NHL, they would not eliminate them; certain views would remain unaffected.	▪ Would have scenic impacts of moderate magnitude, long-term duration, medium or localized extent, and high probability. ▪ Overall rating for visual impacts from the alternative Industrial Park site would be adverse but non-significant; however, these impacts would have some potential to

Visual Resources (continued)		▪ Overall rating for visual impacts from the Proposed Action would be adverse and significant.	become significant.
Transportation	▪ Would not contribute directly to transportation impacts at either the Salem or Industrial Park sites. ▪ Would be contributing indirectly to ongoing transportation impacts at existing generating stations in the region.	▪ Construction-related impacts on traffic would be of minor magnitude, medium-term duration, small extent, and probable likelihood. ▪ Overall rating for impacts on traffic congestion from the Proposed Action would be non-significant and adverse. ▪ Over the long term, during operation of the proposed HGS, impacts on road, rail and air transportation would be generally negligible.	▪ Construction-related impacts on traffic would be of minor magnitude, medium-term duration, small extent, and probable likelihood. ▪ Overall rating for impacts on traffic congestion from the Proposed Action would be non-significant and adverse. ▪ Over the long term, during operation of the proposed Industrial Park facility, impacts on road, rail and air transportation would be generally negligible.
Farmland and Land Use	▪ Would not adversely affect or alter existing land uses at or near the Salem Site or the Industrial Park. ▪ The Salem Site would continue to be maintained in agricultural production and the Industrial Site would continue to be open space. ▪ Could potentially contribute indirectly to impacts on farmland and land use related to other generation sources.	▪ Construction of a power plant at the Salem site would involve the direct conversion of agricultural lands to an industrialized facility with supporting infrastructure. ▪ No homesteads or residences would be displaced. ▪ In the context of the amount of quality farmland in other areas of Cascade County, the conversion of farmland to developed land required for the plant would be a minor magnitude, long-term (permanent) duration, medium extent, and probable likelihood. ▪ Overall rating for impacts on land	▪ Construction of a power plant at the Industrial Park site would involve the direct conversion of agricultural lands to an industrialized facility with supporting infrastructure. ▪ No homesteads or residences would be displaced. ▪ In the context of the amount of quality farmland in other areas of Cascade County, the conversion of farmland to developed land required for the plant would be a minor magnitude, long-term (permanent) duration, medium extent, and probable likelihood. ▪ Overall rating for impacts on land

Farmland and Land Use (continued)		use from the construction phase of the power plant would be adverse and non-significant ▪ Operation of the power plant at the Salem Site would cause no additional direct impacts to land use or farmland. ▪ However, the influence and impacts of the power plant and its associated support facilities could indirectly influence land uses on adjoining or nearby properties in the vicinity of the site. ▪ Development of the Salem Site may reduce market values of nearby rural, agricultural land, affecting sales of those lands. Property values are less likely to be affected, but if they are reduced then there would be repercussions on land assessments and property taxes. ▪ Overall rating for impacts at Salem would be adverse and non-significant, but with some potential for the impacts to become significant.	use from the construction phase of the power plant would be adverse and non-significant. ▪ Operation of the power plant at the Industrial Park Site would cause no additional direct impacts to land use or farmland. ▪ Indirectly, however, the greater proximity of residential areas and other businesses to the Industrial Park site could potentially create more land use conflicts than at the Salem Site. ▪ Development of the Industrial Park Site may reduce the market values of nearby agricultural or residential land, affecting sales of those lands. Property values are less likely to be affected, but if they are reduced then there would be repercussions on land assessments and property taxes. ▪ The impacts on land use from the operation of a power plant at the Industrial Park Site would be minor magnitude, long-term duration, medium extent, and possible likelihood. ▪ Overall rating for impacts at the Industrial Park would be adverse and non-significant, but with some potential for the impacts to become significant.

Waste Management	▪ Would not create any waste management issues on either the Salem or Industrial Site, as no waste would be generated at the sites. ▪ By purchasing an equivalent amount of power from generation sources elsewhere, SME would be contributing indirectly to waste management impacts associated with existing or new generating stations in or outside the region.	▪ Construction-related impacts on waste management would be of minor magnitude, medium-term duration, small extent, and probable likelihood. ▪ Ash and water treatment system byproducts would be disposed of in an onsite monofill which would be managed with appropriate environmental controls, including groundwater monitoring. ▪ Operation-related impacts would be of moderate magnitude, long-term duration, medium extent, and probable likelihood. ▪ Overall waste management impacts would likely be non-significant, but with some potential to become significant.	▪ Construction-related impacts on waste management would be of minor magnitude, medium-term duration, small extent, and probable likelihood. ▪ All non-hazardous waste generated during operation of the power plant, including ash, would be disposed of at the HPSL. ▪ Operation-related impacts on waste management for the Industrial Site would be of minor to moderate magnitude, long-term duration, small extent, and probable likelihood. ▪ Overall waste management impacts would likely be non-significant, but with some potential to become significant.
Human Health and Safety	▪ Would not create any notable risks to human health and safety at, or because of, the sites. ▪ By purchasing power from other generation sources, SME would be contributing indirectly to ongoing human health and safety impacts at different generating stations in the region.	▪ Construction-related impacts at the Salem site would be of minor magnitude, medium-term duration, small extent, and probable likelihood. ▪ Operation-related impacts on human health and safety for the Salem site would be of minor magnitude, long-term duration, medium extent, and probable likelihood. ▪ Overall health and safety impacts of the plant would be adverse but non-significant.	▪ Construction-related impacts at the Industrial Park site would be of minor magnitude, medium-term duration, small extent, and probable likelihood. ▪ Operation-related impacts on human health and safety for the alternative site would be of minor magnitude, long-term duration, medium extent, and probable likelihood. ▪ Overall health and safety impacts of the plant would be adverse but non-significant.

Socioeconomic Environment	▪ Due to the higher electric rates it would likely lead to for SME's members and consumers, the socioeconomic impacts from the No Action Alternative would be potentially significant and adverse.	▪ Construction of the HGS would have a moderately beneficial effect on the socioeconomic environment of the local and regional area, including increases in employment opportunities, total purchases of goods and services, and an increase in the tax base. ▪ During the long term operation of the HGS, it would yield beneficial and potentially significant socio-economic impacts on aggregate income, employment, and population in Great Falls and Cascade County. ▪ HGS would also provide reliable electricity at reduced rates for SME's customer base.	▪ Construction of the Industrial Park facility would have a moderately beneficial effect on the socioeconomic environment of the local and regional area, including increases in employment opportunities, total purchases of goods and services, and an increase in the tax base. ▪ During the long term operation of the facility at the Industrial Park site, it would yield beneficial and potentially significant socioeconomic impacts on aggregate income, employment, and population in Great Falls and Cascade County. ▪ The Industrial Park facility would also provide reliable electricity at reduced rates for SME's customer base.
Environmental Justice/Protection of Children	▪ No direct impact or effect from a power plant on persons living in poverty or children at either site. ▪ Higher electricity prices could disproportionately affect low-income residential consumers. ▪ Impacts would be moderate magnitude, intermittent-term duration, small extent, and possible likelihood.	▪ Would have a negligible effect on children or persons living in poverty, as these population groups are not generally present at or near the Salem Site.	▪ Some potential of a slightly increased risk of impacting children and persons living in poverty from this site, due to the fact that it is located in closer proximity to higher population areas and additional industrial sites. ▪ Impact of minor magnitude, long-term duration, medium extent, and improbable likelihood. ▪ Overall impacts would be adverse but non-significant.